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Air Quality Issues in Natural Gas Systems

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Summary

Natural Gas Systems and Air Pollution

Congressional interest in U.S. energy policy has focused in part on ways through which the United States could secure more economical and reliable fossil fuel resources both domestically and internationally. Recent expansion in natural gas production, primarily as a result of new or improved technologies (e.g., hydraulic fracturing, directional drilling) used on unconventional resources (e.g., shale, tight sands, and coal-bed methane), has made natural gas an increasingly significant component in the U.S. energy supply. This expansion, however, has prompted renewed questions about the potential impacts of natural gas systems on human health and the environment, including impacts on air quality. Unlike the debate over groundwater contamination or induced seismicity—where questions exist as to whether or not production activities contribute significantly to these impacts—there is little question that natural gas systems emit air pollutants. The concerns, instead, are the following:

- Which pollutants?
- How much of each pollutant?
- From which sources?
- What are the impacts of the emissions?
- How much is the cost of abatement?
- What are the respective roles of federal, state, and local governments?

Air pollutants are released by natural gas systems through the leaking, venting, and combustion of natural gas; the combustion of other fossil fuel resources; and the discharge of particulate matter during associated operations. Emission sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, methane and volatile organic compounds—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—as well as nitrogen oxides, sulfur dioxide, particulate matter, and various forms of hazardous air pollutants.

EPA's 2012 Air Standards

The U.S. Environmental Protection Agency (EPA), in response to a consent decree issued by the U.S. Court of Appeals, D.C. Circuit, promulgated air standards for several source categories in the crude oil and natural gas sector on August 16, 2012. These standards—effective October 15, 2012—revised existing rules and promulgated new ones to regulate emissions of volatile organic compounds (VOCs), sulfur dioxide, and hazardous air pollutants (HAPs) from many production and processing activities that had never before been covered by federal oversight. The standards control air pollution, in part, through the capture of fugitive releases of natural gas. Thus, compliance with the standards has the potential to translate into economic benefits, as producers may be able to offset abatement costs with the value of product recovered and sold. Using this assumption, EPA estimated the annual benefits of the standards to be VOC reductions of 190,000 tons, HAP reductions of 12,000 tons, methane reductions of 1.0 million tons, and a net cost savings of $11 million to $19 million after the sale of recovered product. Industry and other stakeholders have disputed these figures as both too high and too low. Moreover, the expansion of both industry production and government regulation of natural gas has sparked discussion on a number of outstanding issues, including the following:

- defining the roles of local, state, and federal governments,
- determining the proper coverage of pollutants and sources,
- establishing comprehensive emissions data,
- understanding the human health and environmental impacts of emissions, and
- estimating the costs of pollution abatement.

Scope and Purpose of This Report

The report begins by briefly outlining the production, processing, transmission, and distribution phases of the natural gas industry, then characterizes the types and sources of pollutants in the sector. It then turns to the role of the federal government in regulating these emissions, including the provisions in the Clean Air Act and the regulatory activities of the EPA. It concludes with an extended discussion of the aforementioned outstanding issues. For an abbreviated version of this report, see CRS Report R42986, *Air Quality Issues in Natural Gas Systems: In Brief*.

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Background

Congressional interest in U.S. energy policy has focused in part on ways through which the United States could secure more economical and reliable fossil fuel resources both domestically and internationally. Recent expansion in natural gas production, primarily as a result of new or improved technologies (e.g., hydraulic fracturing)[1] used on unconventional resources (e.g., shale, tight sands, and coal-bed methane),[2] has made natural gas an increasingly significant component in the U.S. energy supply. While the practice of hydraulic fracturing is not new, relatively recent innovations have incorporated processes such as directional drilling, high-volume slick-water injection, and multistage fractures to get to previously unrecoverable resources. As a result, the United States has again become the largest producer of natural gas in the world.[3] The U.S. Energy Information Administration (EIA) projects unconventional gas activity to more than double from 2010 to 2040, and forecasts that it will make up almost 80% of total U.S. natural gas production by 2040.[4] In addition, some analysts believe that by significantly expanding the domestic gas supply, the exploitation of new unconventional resources has the potential to reshape energy policy at national and international levels—altering geopolitics and energy security, recasting the economics of energy technology investment decisions, and shifting trends in greenhouse gas (GHG) emissions.[5]

Many in both the public and private sector have advocated for the increased production and use of natural gas because the resource is domestically available, economically recoverable, and considered a potential "bridge" fuel to a less polluting and lower GHG-intensive economy.[6] Natural gas is cleaner burning than its hydrocarbon rivals, emitting, on average, about half as much carbon dioxide as coal and one-quarter less than oil when consumed in a typical electric

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[1] Hydraulic fracturing (hydrofracking, fracking, or fracing) is commonly defined as an oil or gas well completion process that directs pressurized fluids typically containing any combination of water, proppant, and any added chemicals to penetrate tight rock formations, such as shale or coal formations, in order to stimulate the oil or gas residing in the formation, and that subsequently requires high-rate, extended flowback to expel fracture fluids and solids. The National Petroleum Council estimates that hydraulic fracturing will account for nearly 70% of natural gas development within the next decade, see National Petroleum Council, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," September 15, 2011. For more discussion on this technology, see the section on "Hydraulic Fracturing" in CRS Report R42333, *Marcellus Shale Gas: Development Potential and Water Management Issues and Laws*, by Mary Tiemann et al.

[2] These unconventional resources are commonly defined as follows: Tight sands gas is natural gas trapped in low permeability and nonporous sandstones. Shale gas is natural gas trapped in shale deposits, a very fine-grained sedimentary rock that is easily breakable into thin, parallel layers. Coal-bed methane is natural gas trapped in coal seams. These resources are referred to as "unconventional" because, in the broadest sense, they are more difficult and/or less economical to extract than "conventional" natural gas, usually because the technology to reach them has not been developed fully, or has been too expensive. For a more detailed discussion of these definitions, see the Natural Gas Supply Association's website, http://www.naturalgas.org/overview/unconvent_ng_resource.asp.

[3] The United States surpassed Russia as the world's leading producer of dry natural gas beginning in 2009. See U.S. Energy Information Administration, "Today in Energy," March 13, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=5370.

[4] U.S. Energy Information Administration, *Annual Energy Outlook, 2013*, http://www.eia.gov/energy_in_brief/article/about_shale_gas.cfm.

[5] For more discussion on natural gas resources, see CRS Report R42814, *Natural Gas in the U.S. Economy: Opportunities for Growth* , by Robert Pirog and Michael Ratner.

[6] Support for the natural gas industry has come also from the Obama Administration. In his 2012 State of the Union speech, President Obama stated, "We have a supply of natural gas that can last America nearly 100 years, and my administration will take every possible action to safely develop this energy." President Barack Obama, "Remarks by the President in State of the Union Address," Washington, DC, January 24, 2012, http://www.whitehouse.gov/the-press-office/2012/01/24/remarks-president-state-union-address.

utility plant.[7] Further, natural gas combustion emits no mercury—a persistent, bioaccumulative neurotoxin—virtually no particulate matter, and less sulfur dioxide and nitrogen oxides, on average, than either coal or oil. For these reasons, pollution control measures in natural gas systems have traditionally received less attention relative to those in other hydrocarbon industries. However, the recent increase in natural gas production, specifically from unconventional resources, has raised a new set of concerns regarding environmental impacts. These concerns centered initially on water quality issues, including the potential contamination of groundwater and surface water from hydraulic fracturing and related production activities. They have since incorporated other issues, such as water management practices (both consumption and discharge), land use changes, induced seismicity, and air pollution. The new set of questions about hydraulic fracturing in unconventional reservoirs has led, in part, to various grassroots movements, some political opposition, and calls for additional regulatory actions, moratoria, and/or bans at the local, state, and federal levels.

Currently, the development of natural gas in the United States is regulated under a complex set of local, state, and federal laws that addresses many—but not all—aspects of exploration, production, and distribution. State and local authorities are responsible for virtually all of the day-to-day regulation and oversight of natural gas systems. The organization of this oversight within each gas-producing jurisdiction varies considerably. In general, each state has one or more regulatory agencies that may permit wells, including their design, location, spacing, operation, and abandonment, and may regulate for environmental compliance. With respect to pollution controls, state laws may address many aspects of water management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety.

Furthermore, several federal statutes address pollution control measures in natural gas systems; and, where applicable, these controls are largely implemented by state and local authorities. For example, the Clean Water Act (CWA) regulates surface discharges of water associated with natural gas drilling and production, as well as contaminated storm water runoff from production sites.[8] The Safe Drinking Water Act (SDWA) regulates the underground injection of wastewater from crude oil and natural gas production, and the underground injection of fluids used in hydraulic fracturing if the fluids contain diesel fuel.[9] The Clean Air Act (CAA) limits emissions from associated engines and gas processing equipment, as well as some natural gas extraction, production, and processing activities.

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[7] These values are averages based on carbon dioxide emitted per unit of energy generated. See Energy Information Administration (EIA), Office of Oil and Gas. Carbon Monoxide: derived from EIA, *Emissions of Greenhouse Gases in the United States 1997*, Table B1, p. 106, ftp://ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/gg98rpt/057397.pdf. Other pollutants derived from U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Vol. 1, Stationary Point and Area Sources*, 1998, http://www.epa.gov/ttn/chief/ap42/.

[8] For more discussion, see CRS Report R42333, *Marcellus Shale Gas: Development Potential and Water Management Issues and Laws*, by Mary Tiemann et al.

[9] For more discussion, see CRS Report R41760, *Hydraulic Fracturing and Safe Drinking Water Act Regulatory Issues*, by Mary Tiemann and Adam Vann.

The Natural Gas Industry

Natural gas is a nonrenewable fossil fuel that is used both as an energy source (for heating, transportation, and electricity generation) and as a chemical feedstock (for such varied products as plastic, fertilizer, antifreeze, and fabrics). Raw natural gas is commonly recovered from geologic formations in the ground through drilling and extraction activities by the oil and gas industry.[10] This industry includes operations in the extraction and production of crude oil and natural gas, as well as the processing, transmission, and distribution of natural gas. For both operational and regulatory reasons, the sector is commonly separated into four major segments: (1) crude oil and natural gas production, (2) natural gas processing,[11] (3) natural gas transmission and storage, and (4) natural gas distribution (see **Figure 1**). This report uses these basic categories to track the various activities in natural gas systems, including the operations, emissions, and regulations discussed below. While the focus of this report is on the production sector, it also highlights air quality issues in other sectors, where appropriate. Below is a brief outline of the crude oil and natural gas industry.[12] For more detail regarding specific activities or equipment, see the glossary of terms provided in **Table C-1**.

Production (Upstream). Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation, and treating of oil and/or natural gas (including condensate). Production operations span the initial well drilling, hydraulic fracturing, well completion, and workover activities and cover all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the ''pads'' where the wells are located, but also the stand-alone sites where oil, condensate, produced water, and gas from several wells may be separated, stored, and treated, as well as the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

Processing (Midstream). Natural gas is primarily made up of methane. However, in its raw state, natural gas is a mixture of various hydrocarbons and may contain trace amounts of other chemical substances that must be removed before distribution. The additional hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. Raw natural gas may also contain water vapor, nonhydrocarbon compounds, and other chemical substances. Processing operations are used to separate out the additional components from raw natural gas to produce ''pipeline quality'' or "dry" natural gas for consumption.

Transmission and Storage (Downstream). Dry natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines, that carry natural gas across state boundaries, or intrastate pipelines, that transport the gas within a single state. While interstate pipelines may be of a larger diameter and operate at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compressor stations are required at regular

[10] Natural gas can also be recovered as a byproduct from various other sources including mining, industrial, or agricultural processes. These secondary sources are not discussed in this report. For a more detailed description of the oil and gas industry, see CRS Report R40872, *U.S. Fossil Fuel Resources: Terminology, Reporting, and Summary*, by Carl E. Behrens, Michael Ratner, and Carol Glover.

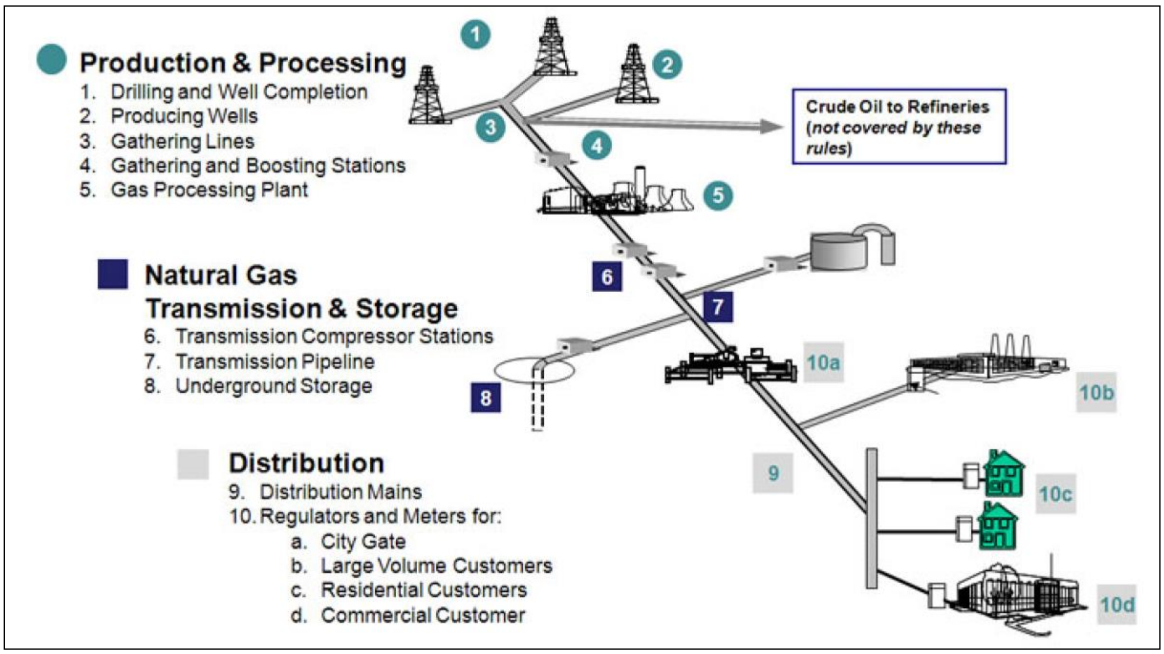
[11] Crude oil after the production phase (i.e., beginning with petroleum refining) is classified as a different industrial sector for most regulatory purposes. Petroleum refining is not discussed in this report. See CRS Report R41478, *The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies*, by Anthony Andrews et al.

[12] The description of the natural gas sector is drawn from the U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," 76 *Federal Register* 52738, August 23, 2011.

intervals. Further, to ensure proper load balancing during the delivery and receipt of natural gas, the transmission segment often includes storage facilities, typically consisting of both man-made and natural sites, such as depleted gas reservoirs and/or salt dome caverns.

Distribution. The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines and then flows to business and household customers. Nationwide, natural gas distribution systems consist of thousands of miles of pipes, including mains and service lines to the customers. Distribution systems also include compressor and metering stations, which allow companies to both move and monitor the natural gas in the system. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the "citygate." Typically, the citygate serves as the transfer point of ownership from producers to utilities.

Figure 1. The Natural Gas Industry



Source: U.S. Environmental Protection Agency.

Air Quality Issues in Natural Gas Systems

Raw natural gas is a mixture of various hydrocarbons (primarily methane) and may contain trace amounts of other chemical substances that must be removed before distribution. Air pollutants associated with the natural gas industry may be emitted through the release of natural gas vapors (either purposefully or accidently), the combustion of natural gas (either for use or for safety/disposal), the combustion of other fuel resources (for process heat, power, and electricity), and the discharge of particulate matter during construction, transportation, and associated operations. Sources of emissions include pad, road, and pipeline construction; drilling, completion, and flowback activities that occur during the development of a well; and gas processing and transmission equipment such as controllers, compressors, dehydrators, pipelines, and storage vessels. Pollutants include, most prominently, methane and volatile organic compounds, of which the natural gas industry is one of the highest emitting industrial sectors in the United States.[13] Pollutants also include nitrogen oxides, sulfur dioxide, particulate matter, and various forms of hazardous air toxics, including n-hexane, the BTEX compounds (i.e., benzene, toluene, ethylbenzene, and xylene), and hydrogen sulfide.

Emissions

Natural gas systems release air emissions in several ways. This report categorizes these emissions into three types: *fugitive, combusted*, and *associated*.[14]

Fugitive. *Fugitive* refers to the natural gas vapors that are released to the atmosphere during industry operations. Fugitive emissions can be either intentional (i.e., vented) or unintentional (i.e., leaked).[15] Intentional emissions are releases that are designed specifically into the system: for example, emissions from vents or blow-downs used to guard against over-pressuring; or gas-driven equipment used to regulate pressure, store, or transport the resource. Conversely, unintentional emissions are releases that result from uncontrolled leaks in the system: for example, emissions from routine wear, tear, and corrosion; improper installation or maintenance of equipment; or the overpressure of gases or liquids in the system. Fugitive natural gas is primarily a mixture of low molecular-weight hydrocarbon compounds that are gaseous in form at normal conditions. While the principal component of natural gas is methane (CH_4), it may contain smaller amounts of other hydrocarbons, such as ethane, propane, and butane, as well as heavier hydrocarbons. These nonmethane hydrocarbons include types of volatile organic compounds (VOCs), classified as ozone (i.e., smog) precursors, as well as, in some cases, hazardous (i.e., toxic) air pollutants (HAPs). Nonhydrocarbon gases, such as carbon dioxide (CO_2), helium (He), hydrogen sulfide (H_2S), nitrogen (N_2), and water vapor (H_2O), may also be present in any proportion to the total hydrocarbon content. The chemical composition of raw natural gas varies greatly across resource reservoirs, and the gas may or may not be "associated" with crude oil resources. When natural gas is found to be primarily methane, it is referred to as "dry" or "pipeline quality" gas. When natural gas is found bearing higher percentages of heavier hydrocarbons, nonhydrocarbon gases, and/or water vapor, it is commonly referred to as "wet,"

[13] For more discussion, see section "Pollutants" of this report.

[14] EPA categorizes emissions as either "equipment leaks and vented emissions" or "combustion-related emissions." See U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, Washington, DC, EPA 430-R-11-005, April 2011.

[15] For further definitions of fugitive emissions, see U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010*, Washington, DC, EPA 430-R-12-001, April 15, 2012, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf.

"rich," or "hot" gas. Similarly, quantities of VOCs, HAPs, and H_2S can vary significantly depending upon the resource reservoir. VOC and HAP compositions typically account for only a small percentage of natural gas mixtures; however, this ratio increases the "wetter" the gas. Natural gas mixtures with a higher percentage of H_2S are generally referred to as "sour" or "acid" gas.[16]

Combusted. *Combusted* refers to the byproducts that are formed from the burning of natural gas during industry operations. Combusted emissions are commonly released through either the flaring of natural gas for safety and health precautions or the combustion of natural gas for process heat, power, and electricity in the system (e.g., for compressors, dehydrators, and other machinery). The chemical process of combusting natural gas releases several different kinds of air pollutants, including carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxides (NO_x), and trace amounts of sulfur dioxide (SO_2) and particulate matter (PM). Flaring is a means to eliminate natural gas that may be impracticable to use, capture, or transport. As with venting, the primary purpose of flaring is to act as a safety device to minimize explosive conditions. Gas may be flared at many points in the system; however, it is most common during the drilling and well completion phases. Natural gas combustion is generally considered a greater pollution control mechanism than the venting of natural gas, because the process serves to incinerate many of the VOCs and HAPs that would otherwise be released directly into the atmosphere. Similarly, natural gas combustion is generally considered as "cleaner" than other fossil fuel combustion with respect to various criteria pollutants and greenhouse gas (GHG) emissions.[17]

Associated. *Associated* refers to secondary sources of emissions that arise from associated operations in natural gas systems. Associated emissions may result from the combustion of other fossil fuels (i.e., other than the natural gas stream) to power equipment, machinery, and transportation, as well as the associated release of dust and particulate matter from construction and road use. Associated emissions have the potential to contribute significantly to air pollution.

The focus of this report is on fugitive and combusted natural gas emissions. While there may be significant emissions from the natural gas sector as a result of the combustion of other fossil fuels for process heat, power, and transportation, as well as the associated release of particulate matter from construction and road use, the primary focus of this report is on air quality issues related to the resource itself (i.e., the fugitive release of natural gas and its combustion during operations). It is this release of natural gas—and the pollutants contained within it—that makes air quality considerations in the crude oil and natural gas sector unique from other industrial-, construction-, and transportation-intensive sectors.

Sources

Natural gas systems include many activities and pieces of equipment that have the potential to emit air pollutants. Most of these emissions sources are common to both conventional and unconventional natural gas development.

Drilling. Fugitive natural gas and other air pollutants may escape to the atmosphere during initial drilling operations through the circulation of drilling fluids back to the surface. Further, emissions from combusted natural gas—including CO_2, NO_x, and potentially SO_2—may also be released at

[16] For more discussion on the chemical composition of raw natural gas emissions, see **Appendix B**.

[17] For more discussion on emissions from combusted fossil fuel resources, see **Appendix B**. While there is general agreement that the combustion of natural gas produces less GHG emissions than other combusted fossil fuels, the GHG emission intensity for the full fuel life-cycle of natural gas (i.e., from extraction through combustion), compared to petroleum and coal is under greater debate. For further discussion on the comparable impacts of the natural gas industry on GHG emissions, see section "Greenhouse Gases."

the well site due to both engine combustion and flaring activities. These include "well test flaring," which occurs during the drilling and testing of oil and gas wells, and "solution gas flaring," which occurs during the disposal of associated gas produced along with crude oil (as is the case currently with oil production in the Bakken formation).

Well Completions. Well completions contain several processes which have the potential to emit air pollutants. For example, hydraulic fracturing uses pressurized fluids containing any combination of water, proppant, and added chemicals to penetrate and produce natural gas from tight formations (e.g., shale, sand, or coal formations). The process requires a high rate, extended flowback period to expel fracture fluids and solids from the well. Gas may escape with these fluids during flowback or impoundment, allowing emissions of methane and VOCs to be released to the atmosphere. Conversely, if the flowback gas is captured, separated from the fluids, and flared, emissions of nitrous oxides and carbon dioxide may be released to the atmosphere. EPA estimates that well completions involving hydraulic fracturing can vent substantially more natural gas—approximately 230 times more—than well completions not involving hydraulic fracturing,[18] if not controlled by reduction equipment.[19] Other sources from industry and academia estimate these emissions levels differently, in part because the data are limited.[20]

Compressors. There are many locations throughout the natural gas sector where compression is required to move gas along the pipeline. This is accomplished by different machinery such as combustion turbines, reciprocating internal combustion engines, and electric motors. Both the turbine-powered centrifugal compressors and the reciprocating internal combustion compressors may use a small portion of the natural gas they compress to fuel the turbine. Both are potential sources of fugitive VOCs and methane emissions as well as significant sources of combusted emissions. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the casing. The seals in some compressors use oil (e.g., "wet seal compressors"), and they commonly vent the absorbed gas to the atmosphere when they are purged. Reciprocating compressors, on the other hand, leak natural gas throughout the course of their normal operation, with the highest volume of gas loss associated with worn down piston rod packing systems. Using dry-seal centrifugal systems or periodically replacing worn down rod packing systems are the most effective ways of controlling emissions from gas-driven compressors. Conversely, where available, electric motors can be used to operate compressors. This type of compression does not require the use of any of the natural gas from the pipeline, but it does require a source of electricity.

Controllers. Pneumatic controllers are automated instruments widely used in the natural gas sector for maintaining pressure, temperature, and flow rate conditions in the system. In many situations, the pneumatic controllers make use of the available high-pressure natural gas in the system to regulate these conditions. In these "gas-driven" pneumatic controllers, natural gas may be released intermittently with every valve movement or continuously from the valve control pilot. Gas driven pneumatic controllers are typically characterized as either "high-bleed" or "low-bleed," where a high-bleed device releases at least 6 cubic feet of gas per hour. Conversely, "non-

[18] Specifically, EPA estimates uncontrolled well completion emissions for a hydraulically fractured well at about 23 tons of VOCs, and emissions for a conventional gas well completion at around 0.1 ton VOCs. See EPA, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," 76 *Federal Register* 52738, August 23, 2011.

[19] Reduced emission completions (REC), which are sometimes referred to as "green completions" or "flareless completions," use equipment at the well site to capture and treat gas so it can be directed into the sales line and avoid emissions from venting. Based on information provided to EPA Natural Gas STAR program, over 90% of gas potentially vented during a completion can be recovered during a reduced emission completion. For more discussion of REC and a schematic, see **Figure 3**.

[20] For further discussion, see section "Measurement of Emissions" of this report.

gas driven" pneumatic controllers use sources of power other than pressurized natural gas, greatly reducing levels of emissions. Examples include solar, electric, and instrument air.

Storage Vessels. After being separated from the natural gas stream, crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. These vessels, which are operated at or near atmospheric pressure conditions, can release various emissions to the atmosphere as a result of working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. The two ways of controlling tanks with significant emissions are to install vapor recovery units (VRU) or to route the emissions from the tanks to control devices (i.e., flares).

Dehydrators. Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. One of the most widely used natural gas dehydration processes is glycol dehydration. Glycol dehydration is an absorption process in which a liquid absorbent (glycol) directly contacts the natural gas stream and absorbs both the entrained water vapor as well as a number of selected hydrocarbons, including BTEX, n-hexane, and other HAPs. During the recirculation stages, the hydrocarbons are boiled off along with the water and are either vented to the atmosphere or directed to a control device.

General Equipment and Pipeline Leaks. Fugitive emissions can emanate from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components at any point during operations. Leaks may be due to routine wear, tear, and corrosion; improper installation or maintenance; or the overpressure of gases or liquids in the system. Because of the large number of valves, pumps, and other components within a natural gas production, processing, or transmission facility, equipment leaks collectively can be a significant source of emissions. Further, there are over 300,000 miles of transmission pipelines alone in the United States, and these pieces of equipment exist throughout the system.

Workovers, Maintenance, and Upsets. Periodically, wells require restimulation workovers or routine maintenance—such as the unloading of liquids or blowdowns—in order to reestablish productive gas flows. These activities, depending upon their methods, may release significant amounts of fugitives into the atmosphere. Further, all activities are susceptible to occasional upsets and accidental losses.

Pollutants

Through provisions in the Clean Air Act (CAA),[21] the U.S. Environmental Protection Agency (EPA) classifies air pollutants under several different categories, including the following:

- **Criteria Pollutants.** Common emissions that can harm human health or the environment, or cause property damage, including ground-level ozone (i.e., smog), nitrogen oxides, sulfur dioxide, carbon monoxide, particulate matter, and lead,[22]

[21] 42 U.S.C. 7401 *et seq*.

[22] See authorities as defined in 42 U.S.C. 7409.

- **Hazardous Air Pollutants.** Toxic chemicals that are known or suspected to cause cancer or other serious health effects, such as reproductive diseases or birth defects,[23]
- **Greenhouse Gas Pollutants.** Chemical compounds that trap heat in the atmosphere and contribute to the forcing of climate change.[24]

The "Criteria" and "Hazardous Air Pollutant" categories are identified and regulated under specific provisions of the CAA. In contrast, greenhouse gases may be regulated under several different ones.[25] The natural gas industry produces emissions from each of these categories, some of which may overlap (e.g., benzene is a volatile organic compound [VOC]; and it is considered both a ground-level ozone-producing criteria pollutant and a carcinogenic hazardous air pollutant [HAP]). See **Figure 2** for a comparison of air pollution emissions from the natural gas industry against those of other U.S. industrial sectors.

Methane (CH_4). Methane—the principal component of natural gas—is both a precursor to ground-level ozone formation (i.e., smog)[26] and a potent greenhouse gas (GHG), albeit with a shorter climate-affecting time horizon than carbon dioxide.[27] Every process in natural gas systems has the potential to emit methane. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011* (published April 15, 2013) estimates 2011 methane emissions from "Natural Gas Systems" to be 358 billion standard cubic feet (bscf), or 1.5% of the industry's gross national production that year.[28] In 2011, natural gas systems represented nearly 25% of the total methane

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[23] See authorities as defined in 42 U.S.C. 7402.

[24] See authorities as defined in U.S. Environmental Protection Agency, "Endangerment and Cause or Contribute Findings for Greenhouse Gases," 74 *Federal Register* 66496-66516, December 15, 2009.

[25] The "endangerment" language in §§108, 111, 211, 213, 115, and 231 provides fundamental authorities. Also, Section 111(d) provides authority to control GHG emissions from existing sources and Section 111(b) and (e) provide similar authorities for new sources.

[26] While methane is a precursor to ground-level ozone formation, it is less reactive than other hydrocarbons. Thus, EPA has officially excluded it from the definition of regulated hydrocarbons called volatile organic compounds (VOCs). See U.S. Environmental Protection Agency, *Conversion Factors for Hydrocarbon Emission Components*, Washington, DC, EPA-420-R-10-015, July 2010, http://www.epa.gov/otaq/models/nonrdmdl/nonrdmdl2010/420r10015.pdf.

[27] As a greenhouse gas, methane emitted into the atmosphere absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change. According to the Intergovernmental Panel on Climate Change (IPCC) *Fourth Assessment Report (2007)*, in 2004 the cumulative changes in methane concentrations since preindustrial times contributed about 14% to global warming due to anthropogenic GHG sources, making methane the second-leading long-lived climate forcer after CO_2 globally. While the perturbation lifetime for methane is 12 years, CO_2's is considerably longer and does not undergo a simple decline over a single predictable timescale. Instead, the excess carbon is first diluted by the carbon cycle as it mixes into the oceans and biosphere (e.g., plants) over a period of a few hundred years, and then it is slowly removed over hundreds of thousands of years as it is gradually incorporated into carbonate rocks. For further discussion on climate change and its potential impacts, see CRS Report RL34266, *Climate Change: Science Highlights*, by Jane A. Leggett.

[28] EPA reported 2011 GHG emissions from natural gas systems as 177.0 million metric tons of carbon dioxide equivalent ($MMtCO_2e$). EPA reported 2011 GHG emissions from all sources as 6702.3 $MMtCO_2e$. U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, Washington, DC, EPA 430-R-13-001, April 15, 2013, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf. Here, as elsewhere in the report, Greenhouse gases are quantified using a unit measurement called carbon dioxide equivalent (CO_2e), wherein gases are indexed and aggregated against one unit of CO_2. CRS used a conversion factor of 0.4045 $MMtCO_2e$ = 1000 bscf CH_4 at 60 degrees Fahrenheit (15.6 degrees Celsius) and 14.696 psi (1 atm or 101.325 kPa) of pressure. The U.S. Energy Information Administration reports 2011 U.S. natural gas marketed production as 24,036 bscf, see http://www.eia.gov/dnav/ng/hist/n9050us2a.htm. EPA's 2011 emission estimates were revised, in part, by industry information released under the Greenhouse Gas Reporting Program (GHGRP) (for more information about the program, see section on GHG Reporting under "Prior Federal Air Standards and Other Rules for Crude Oil and Natural Gas Systems" of this report). The first GHGRP report by the crude oil and natural gas sector was

emissions from all domestic sources and accounted for about 2% of all GHG emissions in the United States. In each year since 1990, natural gas systems were cited as being the single largest contributor to U.S. anthropogenic (i.e., man-made) methane emissions. Because of methane's effects on climate, EPA has found that it, along with five other well-mixed greenhouse gases, endangers public health and welfare within the meaning of the Clean Air Act.[29]

Volatile Organic Compounds (VOCs)—A Ground-Level Ozone (O_3) Precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 12% of VOC emissions nationwide (and representing 67% of VOC emissions released by industrial source categories).[30] VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction between VOCs and NO_x in the atmosphere contributes to the formation of ozone (i.e., smog). EPA quantifies several health effects associated with exposure to ozone, including premature death, heart failure, chronic respiratory damage, and premature aging of the lungs. Ozone may also exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation, and congestion.[31]

Nitrogen Oxides (NO_x)—A Ground-Level Ozone (O_3) Precursor. Significant amounts of NO_x are emitted at natural gas sites through the combustion of natural gas and other fossil fuels (e.g., diesel). This combustion occurs during several activities, including (1) the flaring of natural gas during drilling and well completions, (2) the combustion of natural gas to drive the compressors that move the product through the system, and (3) the combustion of fuels in engines, drills, heaters, boilers, and other production, construction, and transportation equipment.[32] In addition to ozone formation (see VOCs description above), current scientific evidence links short-term NO_x exposures with adverse respiratory effects including airway inflammation in healthy people and increased respiratory symptoms in people with asthma.

Carbon Monoxide (CO). Similar to NO_x, CO is emitted from combustion processes in stationary and mobile sources. CO can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues.

Sulfur Dioxide (SO_2). SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas. Current scientific evidence links short-term exposures to SO_2 with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms.

released in February 2013. Some 1,800 facilities reported 225 $MMtCO_2e$ of total GHG emissions, of which 83 $MMtCO_2e$ were methane (substantially lower than EPA's 2010 estimate of 215.4 $MMtCO_2e$). Notwithstanding, the industry-reported emissions from the crude oil and natural gas sector accounted for almost 40% of total U.S. anthropogenic methane emissions reported by the GHGRP. For discussion, see section "Measurement of Emissions" of this report.

[29] U.S. Environmental Protection Agency, "Endangerment and Cause or Contribute Findings for Greenhouse Gases," 74 *Federal Register* 66496-66516, December 15, 2009.

[30] The 2008 National Emissions Inventory estimated the crude oil and natural gas sector's VOC emissions at 1.7 million tons. Mobile sources are the highest category for VOC emissions domestically, at 45.2% in 2008. Data for VOCs, as well as the other criteria and HAP pollutants, are derived from EPA's National Emissions Inventory, and can be found at http://www.epa.gov/ttn/chief/eiinformation.html. These figures have been contested by some sources. For further discussion, see the section "Measurement of Emissions" of this report.

[31] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Final National Ambient Air Quality Standards for Ozone*, Research Triangle Park, NC, July 2011.

[32] NO_x emissions from engines and turbines are covered by 40 C.F.R. §60, subpart JJJJ and KKKK respectively.

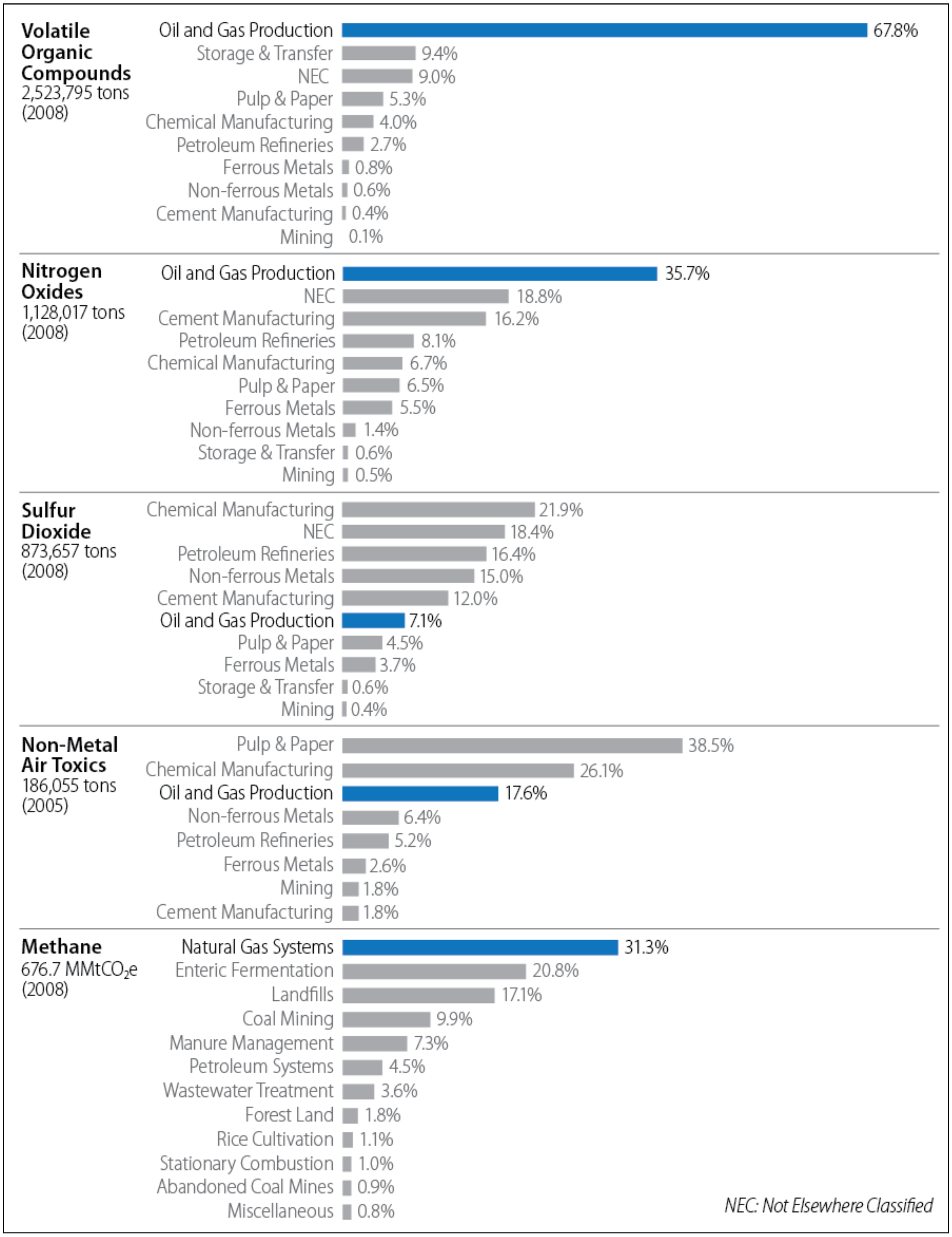
Particulate Matter (PM). PM may occur from dust or soil entering the air during well-pad construction, traffic on access roads, and diesel exhaust from drilling machinery, vehicles, and other engines. PM is linked to respiratory and cardiovascular problems, including aggravated asthma attacks, chronic bronchitis, decreased lung function, heart attacks, and premature death.[33]

Hazardous Air Pollutants (HAPs). HAPs, also known as air toxics, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive diseases, or birth defects. Of the HAPs emitted from natural gas systems, VOCs are the largest group, and typically evaporate easily into the air. The most common HAPs in natural gas systems are n-hexane, the BTEX compounds (benzene, toluene, ethylbenzene, and xylenes), and hydrogen sulfide.[34] HAPs are found primarily in natural gas itself, and are emitted from equipment leaks and from various processing, compressing, transmission, distribution, or storage operations. They are also a byproduct of fuel combustion and may be components in various chemical additives.

[33] U.S. Environmental Protection Agency, *Particulate Matter Health* website, http://www.epa.gov/pm/health.html. For more discussion, see CRS Report R40096, *2006 National Ambient Air Quality Standards (NAAQS) for Fine Particulate Matter (PM2.5): Designating Nonattainment Areas*, by Robert Esworthy.

[34] Hydrogen sulfide was on the original list of hazardous air pollutants in the CAA, Section 112(b), but was subsequently removed by Congress. Currently, hydrogen sulfide is regulated under the CAA's Accidental Release Program, Section 112(r)(3). According to EPA, there are 14 major areas found in 20 different states where hydrogen sulfide is commonly found in natural gas deposits. As a result of drilling in these areas, "the potential for routine [hydrogen sulfide] emissions is significant." See U.S. Environmental Protection Agency, *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas*, EPA-453/R-93-045, Research Triangle Park, NC, October 1993, at ii, III-35; see also ii, II-5 to II-11.

Figure 2. Selected Emissions Inventories for U.S. Industrial Sectors



Source: EPA, National Emissions Inventory 2008, v.1.5 GPR, http://www.epa.gov/ttnchie1/net/2008inventory.html; National Air Toxics Assessment, 2005, http://www.epa.gov/ttn/atw/natamain/; Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html.

The Clean Air Act and the Federal Role in Air Quality Issues in Natural Gas Systems

The Clean Air Act (CAA)[35] seeks to protect human health and the environment from emissions that pollute ambient, or outdoor, air.[36] It requires the U.S. Environmental Protection Agency (EPA) to establish minimum national standards for air emissions from various source categories (sources in the "Crude Oil and Natural Gas Production," and the "Natural Gas Transmission and Storage" sectors are included under these categories), and assigns primary responsibility to the states to assure compliance with the standards. EPA has largely delegated day-to-day responsibility for CAA implementation to all 50 states, including permitting, monitoring, inspections, and enforcement; and in many cases, states have further delegated program implementation to local governments. Sections of the CAA which are most relevant to air quality issues in the natural gas industry are discussed below. Some of the regulations implementing these sections have been revised by federal air standards promulgated by EPA on August 16, 2012. The paragraphs below summarize relevant sections of the CAA prior to these revisions. For a summary of the 2012 air standards and their relationship to the prior ones, see the subsequent section, "2012 Federal Air Standards for Crude Oil and Natural Gas Systems," as well as **Appendix A**.

Prior Federal Air Standards and Other Rules for Crude Oil and Natural Gas Systems

National Ambient Air Quality Standards (NAAQS). Section 109 of the CAA requires EPA to establish NAAQS for air pollutants that may reasonably be anticipated to endanger public health or welfare, and whose presence in ambient air results from numerous or diverse sources. Using this authority, EPA has promulgated NAAQS for sulfur dioxide (SO_2), particulate matter ($PM_{2.5}$ and PM_{10}), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone, and lead. States are required to implement specified air pollution control plans to monitor these pollutants and ensure the NAAQS are met, or "attained." Additional measures are required in areas not meeting the standards, referred to as "nonattainment areas." "Nonattainment" findings for ground-level ozone, nitrogen oxides, and sulfur dioxide in areas with crude oil and natural gas production may result in states establishing specific pollution controls that could affect the industry.

Permits. The 1990 CAA Amendments add Title V (i.e., "5"),[37] which requires major sources of air pollution to obtain operating permits. Primary responsibility for Title V permitting has been delegated by EPA to state and local authorities. Sources subject to the permit requirements generally include new or modified sources that emit or have the potential to emit 100 tons per year of any regulated pollutant, plus new or existing "area sources" that emit or have the potential to emit lesser specified amounts of hazardous air pollutants. In "nonattainment" areas, the permit requirements may include sources which emit as little as 50, 25, or 10 tons per year of VOCs, depending on the severity of the region's nonattainment status ("serious," "severe," or "extreme" respectively). A Title V permit must, among other things, list all emissions limitations and

[35] 42 U.S.C. 7401 et seq. For a summary of the CAA and EPA's air and radiation activities and its authorities, see EPA's website at http://www.epa.gov/air/basic.html; and CRS Report RL30853, *Clean Air Act: A Summary of the Act and Its Major Requirements*, by James E. McCarthy, Claudia Copeland, and Linda-Jo Schierow.

[36] "Outdoor" is defined as that to which the public has access (see 40 C.F.R. §50.1(e)).

[37] 42 U.S.C. §§7661-7661f; 40 C.F.R. §§71, 72.

standards applicable to the source, ensure that monitoring and recordkeeping are sufficient to demonstrate compliance, and require the payment of fees. Currently, most crude oil and natural gas production activities upstream from the processing plant are not classified as "major sources" under EPA Title V operating permits.[38]

Greenhouse Gas Reporting. In the FY2008 Consolidated Appropriations Act (H.R. 2764; P.L. 110-161), Congress directs EPA to develop regulations that establish a mandatory GHG reporting program that applies to emissions that are "above appropriate thresholds in all sectors of the economy." EPA issued the Mandatory Reporting of Greenhouse Gases Rule (MRR)[39] which became effective on December 29, 2009, and included reporting requirements for facilities and suppliers in 32 source categories.[40] Affected facilities in the petroleum and natural gas industry include onshore petroleum and natural gas production, offshore petroleum and natural gas production, natural gas processing, natural gas transmission compressor stations, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export terminals, and natural gas distribution. The rule requires petroleum and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide (CO_2) equivalent per year to report annual fugitive emissions of methane and CO_2 from equipment leaks and venting, and annual combusted emissions of CO_2, methane, and nitrous oxide from gas flaring, from stationary and portable equipment involved in onshore petroleum and natural gas production, and from stationary equipment involved in natural gas distribution. Since methane is the most prominent emission from upstream oil and gas activities, and since the rule requires producers to aggregate emissions from all commonly controlled wells and their associated equipment (e.g., compressors, generators, piping, and storage tanks), many facilities may likely be required to report GHG emissions in coming years.[41] EPA estimates that the rule covers 85% of the total GHG emissions from most of the U.S. petroleum and natural gas industry with approximately 2,800 facilities reporting. On February 5, 2013, EPA released for the first time GHG data for crude oil and natural gas systems collected under industry reporting.[42] Further to this, many states have their own GHG reporting requirements independent of the 2009 federal rules (e.g., the Regional GHG Initiative, the Western Climate Initiative, and California).

New Source Performance Standards (NSPS). Section 111 of the CAA requires EPA to promulgate regulations establishing emissions standards that are applicable to new, modified, and reconstructed sources—if such sources cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. A performance standard reflects

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[38] EPA's guidance for "major source" determinations includes consideration of proximity, ownership, and industrial grouping. For further discussion, see section "Major Source Aggregation."

[39] U.S. Environmental Protection Agency, "Mandatory Reporting of Greenhouse Gases," 74 *Federal Register* 56260, October 30, 2009.

[40] U.S. Environmental Protection Agency, "Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems," 75 *Federal Register* 74458, November 30, 2010, see final rule revision to Subpart W—Petroleum and Natural Gas Systems—amending 40 C.F.R. §98 (i.e., the regulatory requirements for the Program).

[41] In the final rule (40 C.F.R. §98.238), EPA defined "facility" with respect to onshore petroleum and natural gas production to mean "all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR [enhanced oil recovery] operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin [i.e., as defined on a county level and by geologic formation]. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility."

[42] See EPA's GHGRP 2011 data on the agency's website, http://www.epa.gov/ghgreporting/ghgdata/reported/petroleum.html. The data show 2011 GHG emissions from over 1,800 facilities in the crude oil and natural gas sector, accounting for 225 MMtCO2e. For a discussion of these measurements in relation to other reported estimates, see section "Measurement of Emissions" of this report.

the degree of emission limitation achievable through the application of the ‘‘best system of emission reduction’’ (BSER) which EPA determines has been adequately demonstrated. As new technology advances are made, EPA is required to revise and update NSPS applicable to designated sources.

The following federal NSPS may apply to crude oil and natural gas systems (some parts have been rewritten by the August 16, 2012, standards; see the next section and **Appendix A** for further discussion):

- 40 C.F.R. Part 60, Subpart JJJJ—Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE). Subpart JJJJ applies to manufacturers, owners, and operators of SI ICE, which affects new, modified, and reconstructed stationary SI ICE (i.e., generators, pumps, and compressors), combusting any fuel (i.e., gasoline, natural gas, LPG, landfill gas, digester gas etc.), except combustion turbines. The applicable emissions standards are based on engine type, fuel type, and manufacturing date. The regulated pollutants are NO_x, CO, and VOCs, and there is a sulfur limit on gasoline. Subpart JJJJ applies to facilities operating spark ignition engines at compressor stations;
- 40 C.F.R. Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition (CI) ICEs. Subpart IIII applies to manufacturers, owners, and operators of CI ICE (diesel), which affects new, modified, and reconstructed (commencing after July 11, 2005) stationary CI ICE (i.e., generators, pumps, and compressors), except combustion turbines. The applicable emissions standards (phased in Tiers with increasing levels of stringency) are based on engine type and model year. The regulated pollutants are NO_x, PM, CO, and non-methane hydrocarbons (NMHC), while the emissions of sulfur oxides (SO_x) are reduced through the use of low sulfur fuel. Particulate emissions are also reduced by standards. Subpart IIII applies to facilities operating compression ignition engines at compressor stations;
- 40 C.F.R. Part 60, Subpart KKK—Standards of Performance for Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants. Subpart KKK applies to gas processing plants that are engaged in the extraction of natural gas liquids from field gas and contains provisions for VOCs leak detection and repair (LDAR) (this section was revised by the 2012 air standards);
- 40 C.F.R. Part 60, Subpart LLL—Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions. Subpart LLL governs emissions of SO_2 from gas processing plants, specifically gas sweetening units (which remove H_2S and CO_2 from sour gas) and sulfur recovery units (which recover elemental sulfur) (this section was revised by the 2012 air standards); and
- 40 C.F.R. Part 60 Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which construction, reconstruction, or modification commenced after July 23, 1984.

National Emission Standards for Hazardous Air Pollutants (NESHAPs). Section 112 of the CAA requires EPA to promulgate regulations establishing standards to control emissions of hazardous air pollutants (HAPs). NESHAPs are applicable to both new and existing sources of HAPs, and there are NESHAPs for both “major” sources and “area” sources of HAPs. A “major” source of HAPs is one with the potential to emit in excess of 10 tons per year (tpy) of any single HAPs or 25 tpy of two or more HAPs combined. Conversely, an “area” source of HAPs is a stationary source of HAPs that is not major. The aim is to develop technology-based standards which require levels met by the best existing facilities (commonly referred to as maximum achievable control technology, or MACT, standards). The pollutants of concern in the oil and gas sector are primarily the BTEX compounds, formaldehyde, and n-hexane.

The following federal NESHAPs may apply to crude oil and natural gas systems (some parts have been rewritten by the August 16, 2012, standards; see the next section and **Appendix A** for further discussion):

- 40 C.F.R. Part 63, Subpart ZZZZ—National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE);
- 40 C.F.R. Part 63, Subpart H—National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks. Subpart H applies to equipment that contacts fluids with a HAPs concentration of 5%;
- 40 C.F.R. Part 63, Subpart HH—NESHAPs from Oil and Natural Gas Production Facilities. Subpart HH controls air toxics from oil and natural gas production operations and contains provisions for both major sources and area sources of HAPs. Emission sources affected by this regulation are tanks with flash emissions (major sources only), equipment leaks (major sources only), and glycol dehydrators (major and area sources) (this section was revised by the 2012 air standards);
- 40 C.F.R. Part 63, Subpart HHH—NESHAPs from Natural Gas Transmission and Storage Facilities. Subpart HHH controls air toxics from natural gas transmission and storage operations. It affects glycol dehydrators located at major sources of HAPs (this section was revised by the 2012 air standards); and
- 40 C.F.R. Part 61, Subpart V—National Emission Standard for Equipment Leaks (Fugitive Emission Sources). Subpart V applies to equipment that contacts fluids with a volatile HAPs concentration of 10%.

2012 Federal Air Standards for Crude Oil and Natural Gas Systems

On January 14, 2009, two non-governmental organizations filed a complaint under the citizen suit provision of the CAA, alleging that EPA failed to meet its obligations under CAA Sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) to take actions relative to the review/revision of the NSPS and the NESHAPs with respect to the "Crude Oil and Natural Gas Production" source category.[43] On February 4, 2010, the U.S. Court of Appeals for the D.C. Circuit entered a consent decree requiring EPA to sign proposed standards and/or determinations not to issue standards by January 31, 2011 (modified to July 28, 2011), and to take final action by November 30, 2011 (modified to April 17, 2012). EPA proposed a new set of air standards for the "Crude Oil and Natural Gas Production" sector and the "Natural Gas Transmission and Storage" sector on July 28, 2011,[44] and held three public hearings for the proposal. After several court-agreed extensions, the final rules establishing the new standards were signed by the Administrator on April 17, 2012, were published in the *Federal Register* on August 16, 2012,[45] and became effective on October 15,

[43] *WildEarth Guardians, et al. v. Jackson,* No. 1:09-CV-00089-CKK (D. D.C.), https://www.federalregister.gov/articles/2009/12/17/E9-30044/proposed-consent-decree-clean-air-act-citizen-suit.

[44] U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," 76 *Federal Register* 52738, August 23, 2011.

[45] U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012, https://www.federalregister.gov/articles/2012/08/16/2012-16806/oil-and-natural-gas-sector-new-source-performance-standards-and-national-emission-standards-for.

2012. A summary of the 2012 federal air standards is provided below. For a detailed comparison of the 2012 federal air standards against the prior federal air standards, see **Appendix A**.

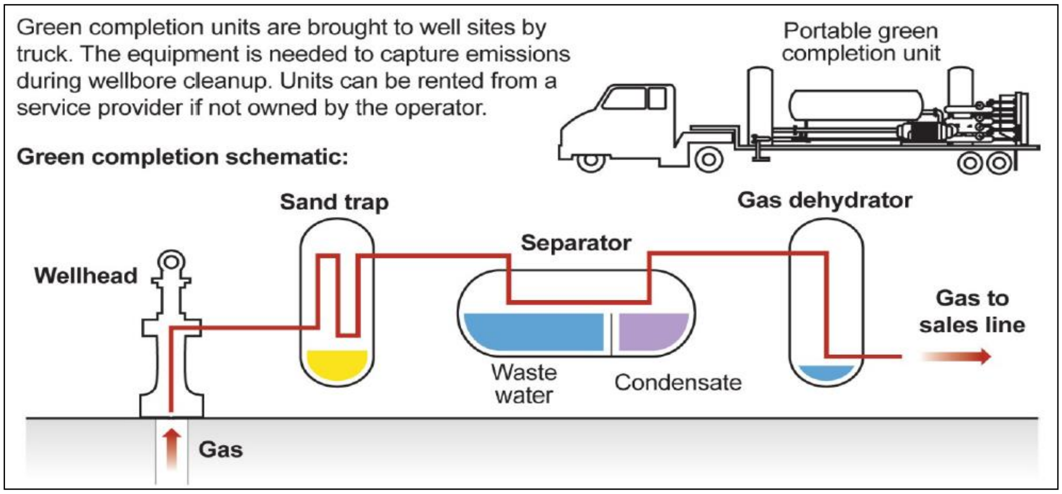
2012 NSPS for Crude Oil and Natural Gas Systems

The 2012 NSPS for the "Crude Oil and Natural Gas Production" and the "Natural Gas Transmission and Storage" source categories regulate volatile organic compounds (VOCs) emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels, and leaking components at onshore natural gas processing plants, as well as sulfur dioxide (SO_2) emissions from onshore natural gas processing plants. Prior to the 2012 standards, processing plants were the only source category regulated at the federal level. The 2012 standards include the following:

- **Gas Wells.** The rule covers any gas well that is "an onshore well drilled principally for production of natural gas" and is "hydraulically fractured." Oil wells (i.e., wells drilled principally for the production of crude oil) or conventional gas wells (i.e., wells drilled without hydraulic fracturing for the production of natural gas) are not subject to the rule. For fractured and refractured gas wells, the rule requires owners/operators to use "reduced emissions completions"—also known as "REC" or "green completions"—to reduce VOCs emissions during well completions. A REC is defined by EPA as "a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere" (see graphic in **Figure 3**). To provide industry enough time to order and manufacture the necessary REC equipment, the NSPS establishes two phases for compliance. Owners and/or operators may use either REC or completion combustion devices (e.g., flaring) until January 1, 2015. After January 1, 2015, REC will be required. The rule exempts exploratory, delineation, and low-pressure gas wells from the REC requirement, stipulating the use of completion combustion devices instead.[46]

[46] Exploratory well is defined as a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists; delineation well is defined as a well drilled in order to determine the boundary of a field or producing reservoir; and low pressure well is defined as a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Figure 3. Reduced Emissions Completion Equipment



Source: U.S. Environmental Protection Agency.

Graphic: Dave Merrill/BGOVgraphics, Bloomberg Government, http://www.bgov.com.

- **Storage Vessels.** The rule requires individual storage vessels in the crude oil and natural gas production segment and the natural gas processing, transmission, and storage segments with emissions equal to or greater than 6 tons per year (tpy) to achieve at least 95% reduction of uncontrolled VOCs emissions.[47]
- **Certain Controllers.** The rule sets a natural gas bleed rate limit of 6 standard cubic feet per hour (scfh) for individual, continuous bleed, natural gas-driven pneumatic controllers located between the wellhead and the point at which the gas enters the transmission and storage segment. For individual, continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants, the rule sets a natural gas bleed limit of zero scfh.
- **Certain Compressors.** The rule requires a 95% reduction of VOCs emissions from wet seal centrifugal compressors located between the wellhead and the point at which the gas enters the transmission and storage segment. The rule also requires measures intended to reduce VOCs emissions from reciprocating compressors located between the wellhead and the point where natural gas enters the natural gas transmission and storage segment. Owners and/or operators of these compressors must replace the rod packing systems within the compressors based on specified usage or time.
- **Onshore Natural Gas Processing Plants.** The rule revises the existing NSPS requirements for leak detection and repair (LDAR) to reflect the procedures and leak thresholds established in the NSPS for equipment leaks of VOCs emissions in the synthetic organic chemicals manufacturing industry. This rule also revises the existing NSPS requirements for SO_2 emission reductions based on sulfur feed rate and sulfur content of gas.

[47] This section is currently under reconsideration in a proposed rule, U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013.

2012 NESHAPs for Crude Oil and Natural Gas Systems

The 2012 rules revise the NESHAPs for glycol dehydration unit process vents and leak detection and repair (LDAR) requirements and retain the existing NESHAPs for storage vessels. The 2012 standards include the following:

- **Glycol Dehydration Units.** The rule establishes MACT standards for "small" glycol dehydration units, which were unregulated under the initial NESHAPs. Covered glycol dehydrators now include those with an actual annual average natural gas flow rate less than 85,000 standard cubic meters per day (scmd) or actual average benzene emissions less than 0.9 megagrams per year (Mg/yr), and they must meet unit-specific limits for benzene, toluene, ethylbenzene, and xylene (collectively, "BTEX").[48]
- **Leak Detection and Repair.** The rule lowers the leak definition for valves at natural gas processing plants from 10,000 parts per million (ppm) to 500 ppm for major sources at crude oil and natural gas production facilities, thus requiring the application of LDAR procedures at this level.

Effects of the 2012 Federal Air Standards on State Attainment Planning and Permitting

With the release of the 2012 air standards for the crude oil and natural gas production, transmission, and storage sectors, EPA constituted a federally required minimum level of control for various source categories. States have the flexibility to put their own programs in place or implement existing programs as long as they are at least as protective as the federal standards.

Attainment Planning. EPA has designated attainment and nonattainment areas for the 2008 ozone National Ambient Air Quality Standards (NAAQS). Some of these areas have significant crude oil and natural gas activities. States with ozone nonattainment areas are required to submit modified state implementation plans (SIP) in 2015 and to attain the standard by 2015 and 2018 for areas classified as "marginal" and "moderate," respectively. A few areas classified as "serious" nonattainment must attain by 2021. As the 2012 air standards may likely help states make progress in attaining the ozone NAAQS in nonattainment areas where there is significant well development, states are allowed to include the federal NSPS as a federally enforceable strategy in their nonattainment SIP. States may "take credit" for the NSPS in their SIP towards meeting two requirements: (1) the 2012 standards are expected to achieve 95% control of VOCs emissions from new gas wells, making it easier for states to obtain the overall reduction in emissions they need to attain the ozone NAAQS without adding any federal or state permitting requirements; and (2) SIPs in "moderate" and "serious" areas must also show "reasonable further progress" in controlling emissions in the years before they attain the ozone NAAQS. In most areas, states may choose to measure this progress relative to emissions in 2011. In areas that had wells drilled in 2011 and will continue to have more wells drilled in the years ahead, the 95% control from the NSPS may provide emission reductions that can be credited toward the reasonable further progress requirement. In areas that had no or few wells drilled in 2011 but that will see drilling activity in the future, the 95% control from the NSPS may ensure that emissions from new well development do not impede meeting the reasonable further progress requirement.

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[48] The final MACT standards for small dehydrators at crude oil and natural gas production facilities require that existing affected sources at a major source meet a unit-specific BTEX limit of 3.28×10^{-4} grams BTEX/standard cubic meters (scm)-parts per million by volume (ppmv) and that new affected sources meet a BTEX limit of 4.66×10^{-6} grams BTEX/scm-ppmv.

Permitting. The 2012 NSPS regulates all new and modified gas wells whether or not they attain existing thresholds that define a "major source" for pre-construction permit and Title V operating permit purposes. In the absence of the NSPS, some hydraulically fractured gas wells could have emissions above these thresholds in some ozone nonattainment areas. Wells complying with the 2012 NSPS, however, most likely will not trigger major source permitting thresholds. Wells complying with the 2012 NSPS may also have emissions low enough to avoid needing a minor source permit from the state, as the NSPS provides a path (i.e., REC) for existing wells that are refractured to avoid falling under the scope of the NSPS at all, thereby avoiding any automatic requirement to get a state minor source permit. Nevertheless, states may still include modified wells in their minor source permitting rules if they choose.

Reported Costs and Benefits of the 2012 Federal Air Standards

Natural gas is a product of—and thus a source of revenue for—the oil and gas industry. It is also a main source of pollution for the industry when it is emitted into the atmosphere. Due to this unique linkage, pollution abatement has the potential to translate into economic benefits for the industry, as producers can offset compliance costs with the value of natural gas and condensate recovered and sold at market. EPA reports the environmental and the economic benefits of the 2012 air standards as follows:[49]

- **VOCs Reductions of 190,000 to 290,000 Tons Annually.** VOCs emissions reductions of nearly 95% from hydraulically fractured gas wells are expected to help reduce ground-level ozone (i.e., smog) in areas where crude oil and natural gas production occurs.
- **Air Toxics Reductions of 12,000 to 20,000 Tons Annually.** The 2012 rules are intended to protect against potential cancer risks from emissions of several air toxics, including the BTEX compounds.
- **Methane Reductions of 1.0 Million to 1.7 Million Short Tons Annually.** (Equivalent to 19 to 33 million metric tons of CO_2 equivalent (CO_2e).) While not targeted by the 2012 rules, methane reductions from new and modified well completions and other activities would yield an additional environmental co-benefit.
- **Industry Costs of $170 Million Annually.** EPA estimates the rule will cost producers about $170 million annually in 2015 (in 2008$). Industry and third party sources have estimated anywhere from $450 million to over $2.8 billion, depending upon assumptions regarding the number of wells subject to compliance, the cost of REC equipment and rentals, and the number and cost of completion combustion requirements.[50]
- **Net Cost Savings for Industry of $11 Million to $19 Million.** EPA estimates that compliance costs would be offset by the sales of the captured methane and natural gas liquids, resulting in a net gain of $11 million to $19 million in 2015. EPA's cost-benefit analysis, as put forth in its *Regulatory Impact Analysis* for the

[49] As reported in U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012.

[50] For reference, U.S. natural gas producers sold about 24 trillion cubic feet of gas in 2011, with a value of $72.5 billion at $3/Mcf. Energy Information Administration, *U.S. Natural Gas Wellhead Value and Marketed Production,* http://www.eia.gov/dnav/ng/ng_prod_whv_dcu_nus_a.htm.

> proposed air standards, has been critiqued as both too high and too low by industry and environmental stakeholders, respectively.[51] Industry stresses that the economic analyses must include the full variety of conditions (e.g., the full range of VOCs content found across different reservoirs) in upstream production activities to support all the costs of compliance with the proposed rule; and that the analysis does not fully take into account the effect that operational standards (i.e., the requirements for additional green completions and other abatement equipment) will have on the production and growth of the industry in the near term.[52] Industry claims that fluctuations in the market price of recovered products may also serve to further depress EPA's revenue estimates. Conversely, environmental stakeholders argue that the costs of control used by EPA are conservative estimates and do not properly account for the full social and environmental benefits created by the capture of methane.[53]

Agency Reconsideration of the 2012 Federal Air Standards

On April 12, 2013, EPA announced proposed amendments to the 2012 federal air standards for the oil and gas sector.[54] The proposed rule reconsiders certain issues related to implementation of the storage vessel provisions and adjusts compliance dates to allow more time for the availability of control devices. In summary, the proposed rule grants reconsideration of the following: (1) an extension to the implementation date for the storage vessel provisions (from October 15, 2013, to April 15, 2014, for new and modified sources after April 12, 2013); (2) definition of "storage vessel" (to clarify that it refers only to vessels containing crude oil, condensate, intermediate hydrocarbon liquids, or produced water); (3) definition of "storage vessel affected facility" (to include the 6 tpy VOC emission threshold); (4) requirements for storage vessels constructed, modified, or reconstructed during the period from the NSPS proposal date, August 23, 2011, to April 12, 2013 (to remove the requirement for control devices and to require instead notification to regulatory agencies by October 15, 2013, of the existence and location of the vessels); (5) an alternative mass-based standard for storage vessels after extended periods of low uncontrolled emissions (to include a sustained uncontrolled VOC emission rate of less than 4 tpy as an alternative emission limit to the 95% control in the final NSPS under specified circumstances).

Issues for Congressional Consideration

The expansion of both industry production and government regulation of natural gas systems has sparked discussion on a number of outstanding issues. Some of the more significant debates involving air quality concerns are outlined in the sections below.

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[51] For further discussion on costs, see section "Cost Benefit Analysis of Federal Standards."

[52] For an example of industry comments on the cost analysis, see comments to "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," submitted by Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute, November 30, 2011, accessed on http://www.regulations.gov.

[53] For an example of environmental stakeholder comments on the cost analysis, see comments to "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," submitted by Sierra Club, et al., November 30, 2011, accessed on http://www.regulations.gov.

[54] U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013.

The Regulatory Role of Federal, State, and Local Governments

According to EPA, the 2012 federal air standards are designed to provide minimum requirements for emissions of air pollutants from the crude oil and natural gas sector that can both protect human health and the environment and allow for continued growth in production. However, some believe that state and local governments are better positioned to develop these emission standards. They claim that states can more readily address the regional and state-specific character of many crude oil and natural gas activities, including differences in geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics, and the effects these components have on air quality. They argue that federal rules add unnecessary and often repetitive requirements on the industry, which may increase project costs and delays with little added benefit. Others, attesting to the "patchwork" of state and local requirements, support the need for the federal government to institute minimum standards for emissions that are consistent, predictable, and reach across state lines. They claim a federal standard would extend regulatory certainties to the industry and would best ensure health and environmental protections for all stakeholders. They also contend that many state laws and state agencies are still gaining experience with unconventional oil and natural gas development, and that industry is operating under insufficient and outdated rules. In light of these considerations, Congress may choose to re-examine proposed and/or existing federal requirements apropos of existing state and local regulations, or introduce new federal requirements if deemed necessary.

Currently, states lead the day-to-day permitting, monitoring, and enforcement of crude oil and natural gas development, and any federal requirements that might apply have typically been delegated to the states. In general, each state has one or more regulatory agencies that may permit wells, including their design, location, spacing, operation, and abandonment, and may regulate for environmental compliance, including water management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. The organization of regulatory agencies within the various oil and gas producing states varies considerably. In many cases, state agencies were established initially to provide a structure to facilitate—not regulate—oil and gas development. These facilitatory agencies served primarily to provide a central state system for administering resource claims and mediating disputes. In some instances, these agencies have taken on oversight activities for environmental protection. In other instances, they have operated alongside a separate agency that has been mandated to prevent environmental pollution and public health impacts.

For example, Colorado provides multiple state agencies with different authorities to regulate industry operations. The Colorado Department of Public Health and Environment (CDPHE) and the Colorado Department of Natural Resources maintain separate but complementary oversight of industry operations. Colorado's Air Quality Control Commission (under CDPHE) has regulations to address emissions from tanks, engines, compressors, and associated equipment. Colorado's Oil and Gas Conservation Commission has regulations pertaining to such issues as well completions, odors, noise, and drill rig setbacks. Conversely, Pennsylvania's Department of Environmental Protection (DEP) Office of Oil and Gas Management is responsible for all statewide oil and gas programs. The office manages activities both to facilitate the exploration, development, and recovery of Pennsylvania's oil and gas reservoirs while also overseeing the protection of the commonwealth's natural resources and environment. The office develops policy and programs for the regulation of oil and gas development pursuant to the commonwealth's Oil and Gas Act, the Coal and Gas Resource Coordination Act, and the Oil and Gas Conservation Law. It oversees the oil and gas permitting and inspection programs, develops statewide regulation and standards, conducts training programs for industry, and works with the Interstate Oil and Gas Compact Commission and the Technical Advisory Board.

All crude oil and natural gas producing states have laws in place related to oil and gas development. Most state requirements are written into rules or regulations. Requirements may also be added to permits on a case-by-case basis as a result of findings from environmental reviews, on-the-ground inspections, public comments, or commission hearings. For example, emissions from oil and gas development in Colorado are governed primarily by statutory provisions of the Oil and Gas Conservation Act (Colo. Rev. Stat. §34-60-100, et seq.), Colorado's Air Pollution and Prevention Control Act (§25-7-100, et seq.), and Water Quality Control Act (§25-8-100, et seq.). In other states, such as Montana or Texas, emissions from oil and gas development are addressed most prominently during permitting, registration, and authorization activities (e.g., Montana Department of Environmental Quality, Air Quality Permits [MAQP], under Rule 17.8.752, and Montana Registration Requirements, under Rule 17.8.1711[1][a]; or Texas Commission on Environmental Quality, Permit by Rule [PBR], Standard Permit, and New Source Review [NSR] Permit, under Title 30, Texas Administration Code, Chapter 116, et seq.).

Most state oil and gas regulations were written well before unconventional natural gas development became widespread. A number of major gas producing states have recently revised regulations, with particular focus on emerging areas of concern, including disclosure of hydraulic fracturing chemicals, well construction and operation to prevent aquifer contamination, and management of waste from flowback and produced water. Similarly, many states and counties have some regulatory structures to address air quality issues based on each jurisdiction's individual circumstance. Some states and counties have adopted relatively stringent standards, while others have not. Some have rules proposed or are in the process of revising or implementing them. Others are considering rolling back existing regulations.[55] EPA's 2012 federal air standards were drawn primarily from existing requirements found in the state codes of Colorado and Wyoming. For a comparison of EPA's 2012 air standards for source categories in the crude oil and natural gas industry to those from selected states, see **Table A-4** of this report.

Critics of federal oversight maintain that the states have long regulated oil and gas exploration and production and are best positioned to continue to do so as they have established governing structures and trained staff in place. They argue that a distant federal bureaucracy unfamiliar with local conditions is rarely the best entity to ensure environmental needs are balanced with economic growth and job creation. They claim that states can more readily address the regional and state-specific character of many crude oil and natural gas activities, including differences in geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. Critics argue that federal rules add unnecessary and often repetitive requirements on the industry, which may increase project costs and delays with little added benefit. They claim federal rules would require increased federal resources and skilled staff to administer regulations for oil and gas development (or, as is sometimes the case, to administer federal requirements redundantly alongside existing state programs). They contend that a well-run state permitting and regulatory program can adjust more quickly, is better positioned to meet the challenges presented by constantly developing technologies, and can effectively administer rules across private, state, and federal lands.[56]

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[55] For example, see New Mexico's current efforts to loosen regulations on pits for waste or drill cuttings and the use of steel tanks as part of a "closed loop" system, Mike Soraghan, "N.M. is loosening drilling rules, bucking trends and riling ranchers," *E&E News,* Thursday, November 15, 2012, http://www.eenews.net/energywire/2012/11/15/1.

[56] For example, see the comments made by Wyoming governor Matthew Mead, as reported in the *Washington Times:* Matthew Mead, "Commentary: Hydro-fracking regulations should be left to states," *Washington Times,* September 17,

Others note that it has neither been the practice nor the intention of EPA to administer regulations for oil and gas development at the state level. However, seeing the patchwork mix of state and local requirements, they have called for the federal government to institute a minimum nationwide standard for emissions from the crude oil and natural gas sector. Proponents of federal oversight contend that many state laws and state agencies are still gaining experience with unconventional oil and natural gas development, and that industry is operating under insufficient and outdated rules.[57] They claim that many of the agencies that regulate development at the state level are underfunded and understaffed, are tasked with the dual purposes of developing the state's resources and protecting the state's environment, and thus, are caught between policing and promoting the industry. They suggest that state agencies and state regulators are often overwhelmed by oil and gas companies, which are generally national or international in scope, and start with the advantage of sheer size. They point to examples where state regulators have failed to seek large penalties for violations or track enforcement data, and cite statistics that show 40% of state drilling regulators have industry ties.[58] A 2012 report, released by a non-governmental environmental organization, surveyed active oil and gas wells in six states and summarized the findings as follows: (1) over half (or close to 350,000 active wells in 2010) are operating with no independent inspections to determine whether they are in compliance with state rules; (2) when inspections do uncover rule violations, the violations often are not formally recorded; (3) when violations are recorded, they result in few penalties; (4) when penalties are assessed, they provide little incentive for companies to not offend again (noting that no state assessed annual fines that added up to the average value of a single gas well, about $2.9 million).[59]

Covered Sources and Pollutants

The 2012 federal air standards focus primarily on the upstream sectors of the oil and gas industry and cover only some of the pollutants and potential sources of emissions. The standards regulate emissions of VOCs from some, but not all, of the equipment and activities at onshore natural gas well sites, gathering and boosting stations, and processing plants. Similarly, the standards regulate emissions of SO_2 from sweetening units at some natural gas processing plants, as well as HAPs from some dehydration units and storage facilities in the sector. Some pollutants from natural gas systems remain uncovered by any federal law or regulation, and critics point specifically to methane emissions from the midstream and downstream sectors, as well as hydrogen sulfide, as the most significant omissions. The scope of the 2012 federal standards are the result of several

2012, http://www.washingtontimes.com/news/2012/sep/17/hydro-fracking-regulations-should-be-left-to-state/#ixzz26uwFzyr3.

[57] For example, see the comments made by Peter Zalzal, Environmental Defense Fund, "National Clean Air Standards For The Oil And Gas Industry Provide a Trifecta," EDF Energy Exchange, March 20, 2012, http://blogs.edf.org/energyexchange/2012/03/20/national-clean-air-standards-for-the-oil-and-gas-industry-provide-a-trifecta/.

[58] As reported in Mike Soraghan, "Puny fines, scant enforcement leave drilling violators with little to fear," *E&E News,* Monday, November 14, 2011, http://www.eenews.net/Greenwire/2011/11/14/archive/1; Mike Soraghan, "40% of state drilling regulators have industry ties," *E&E News,* Monday, December 19, 2011, http://www.eenews.net/Greenwire/ground_rules/2011/12/19/1. The reporting found that in Texas, 96% of the 80,000 violations by oil and gas drillers in 2009 resulted in no enforcement action. West Virginia, a state with 56,000 wells, issued 19 penalties last year. And Wyoming, the center of Rocky Mountain development, collected $15,500 in fines in 2010. Pennsylvania sought penalties for more than a quarter of the violations found last year, but levied fines for only 4% of the violations, with the penalties totaling $3.7 million. Further, the reporting reviewed the backgrounds of 95 oil and gas commissioners, board members and agency heads in the top 27 oil and gas states, and found, 39 had an oil and gas background, or 41%.

[59] Lisa Sumi, *Breaking All the Rules: The Crisis in Oil & Gas Regulatory Enforcement*, Earthworks, Washington, DC, September 25, 2012, http://www.earthworksaction.org/library/detail/breaking_all_the_rules_the_crisis_in_oil_and_gas_regulatory_enforcement.

factors, including (1) EPA-conducted cost-benefit and risk analyses, (2) stakeholder comments provided to the agency during rulemaking, and (3) statutory limitations placed upon the agency by provisions in the CAA. In light of these considerations, Congress may decide to re-examine ways in which oversight activities address the most significant pollutants and point sources.

While the 2012 air standards for crude oil and natural gas systems are more detailed and comprehensive than previous standards, several pollutants and sources in the sector remain uncovered.

The 2012 standards do not directly cover emissions of the following pollutants in the sector: methane, nitrogen oxides, particulate matter, and hydrogen sulfide (although reductions in some of these pollutants may occur as a co-benefit of VOCs and SO_2 reductions). Many observers have noted, however, that the 2012 standards, as written, use natural gas emissions as a surrogate for VOCs and H_2S/SO_2 emissions. Some argue that basing standards on the volume of natural gas emissions as opposed to the content of VOCs in the gas does not adequately account for the geographic variability of VOCs within the resource (e.g., EPA calculated cost effectiveness based on a national average of 3.7% VOCs by volume [18% by weight] for natural gas streams; however, many streams may produce little or no VOCs). Critics of the rule maintain that requiring standards for natural gas emissions as opposed to VOCs content essentially regulates the industry for methane as opposed to VOCs. From this perspective, requiring an operational standard (e.g., reduced emissions completions) instead of a performance standard (e.g., a VOCs threshold) may impose unnecessary compliance costs in some instances.[60] The 2012 standards do address the smaller volume of VOCs in natural gas streams after the processing stage by exempting many activities and pieces of equipment in the transmission, storage, and distribution sectors of the industry.

Further, the 2012 standards do not cover emissions from the following sources in the sector: all oil wells; all off-shore sources; all coal-bed methane production facilities; all field engines, drilling rig engines, and turbines; well-head and transmission and storage segment compressors; well-head activities such as liquids unloading; all heater-treaters; all pneumatic devices other than controllers; storage vessels such as skid-mounted, mobile, well cellars, sumps, and produced water ponds; and LDAR for non-processing plant facilities. Additionally, the 2012 standards do not cover VOCs or SO_2 emissions from existing sources, unless they are classified as HAPs. Finally, the 2012 standards assume non-gas-driven controllers cannot replace gas-driven controllers as "best system of emission reduction" (BSER) for regulatory purposes; low-bleed controllers cannot replace high-bleed controllers as BSER; centrifugal compressors cannot replace reciprocating compressors as BSER; and vapor recovery units cannot replace combustion devices as BSER. Many of these sources may still emit significant quantities of pollutants; however, EPA has determined that standards on these sources are either technically or economically unfeasible.[61]

Major Source Aggregation

The 2012 federal air standards exempt well completions, pneumatic controllers, compressors, and storage vessels from "major source" determination with respect to CAA Title V permit requirements. Viewed at the component level, these smaller "emissions units" at natural gas facilities may not generate enough pollution on their own to be classified as "major sources." However, it may be possible that an entire natural gas operation (e.g., a well site, a field, or a

[60] See comments submitted by Howard J. Feldman, API, *op cit.*

[61] See comments submitted by Sierra Club, *op cit.*

station) is a "major source" (i.e., one that emits typically 10 tons to 250 tons per year, depending upon the pollutant and the area's attainment status). Determining which equipment and activities should be grouped together, or "aggregated," in the crude oil and natural gas sector for permitting purposes remains an open issue for the states, the courts, EPA, and the regulated entities. In light of these considerations, Congress may further assess EPA's requirements for major source categories in upstream oil and gas activities.

The past few decades have seen several developments in the evaluation of crude oil and natural gas facilities at multiple locations for possible aggregation into a single source for permitting purposes. The ability of EPA and the state permitting authorities to aggregate multiple operations into a single major source permit is founded upon the definition of "stationary source" within the CAA. The CAA defines a "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant."[62] *Alabama Power Co. v. Costle*[63] established boundaries on the scope of a source such that "(1) it must carry out reasonably the purposes of New Source Review/Prevention of Significant Deterioration (NSR/PSD); (2) it must approximate a common sense notion of 'plant'; and (3) it must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of 'building,' 'structure,' 'facility,' or 'installation.'"[64] In response, in the 1980 revisions to the PSD regulations, EPA clarified that emissions from operations may be aggregated and considered a single major source for PSD permitting if they meet each of the following three criteria: (1) the sources are located on one or more "contiguous or adjacent" properties, (2) the sources are under common control of the same person (or persons under common control), and (3) the sources belong to a single major industrial grouping (same two digit major Standard Industrial Classification (SIC) code). Only if all three criteria are met will the CAA permitting authority aggregate the operations into a single NSR/PSD permit. After the 1990 CAA Amendments created the Title V Operating Permit Program, this three-factor analysis was extended to Title V major source permitting.

The source definition established by EPA was intended to aggregate only "major projects that would cause air quality deterioration" but "avoid review of projects that would not increase deterioration significantly."[65] EPA has recently addressed the issue of CAA source determinations in the oil and gas industry in a 2009 guidance document from the EPA Office of Air and Radiation (the "McCarthy Memo").[66] The McCarthy Memo withdrew earlier guidance from EPA which concluded that the three prong aggregation analysis for oil and gas activities should begin by looking at and focusing most heavily on the proximity of the surface locations. This emphasis on proximity may have been a result of previous actions by EPA that interpreted "contiguous and adjacent" as meaning "functionally interdependent" (e.g., sources connected by pipelines, conveyors, roads, and other means by which materials and products or intermediate products are transferred between them). The McCarthy Memo attempted to negotiate a path between the broad mandate of "functional interdependence" and the more narrow use of "proximity." It recognized that source determinations in the oil and gas industry continue to be complex, and re-emphasized that the regulations list all three criteria to be used in the analysis. It then acknowledged that there would be cases in which proximity is the "overwhelming factor," but the agency is not going to

[62] 42 U.S.C. §7411 (a)(3).

[63] *Alabama Power Co. v. Costle,* 636 F.2d 323 (D.C. Cir. 1979).

[64] 45 *Federal Register* 52676, August 7, 1980.

[65] 45 *Federal Register* 52676, August 7, 1980.

[66] See "Withdrawal of Source Determinations for Oil and Gas Industries," memorandum from Gina McCarthy to Regional Administrators, September 22, 2009, withdrawing the 2007 EPA memo "Source Determinations for Oil and Gas Industries," memorandum from William L. Wehrum to Regional Administrators, January, 12, 2007.

pre-judge that by using a simplified approach, and that "reasoned decision-making" of each of the relevant factors needs to occur on a case-by-case basis.

EPA's three prong aggregation analysis for oil and gas activities was recently challenged in the case of *Summit Petroleum Corp. v. EPA* before the U.S. Court of Appeals for the 6th Circuit.[67] In an August 7, 2012, decision, the 6th Circuit rejected 2-1 the agency's "functional interrelationship" analysis used to support its definition of "adjacency," vacating EPA's determination that a Michigan natural gas plant and its production wells constitute a single major source. Further, on October 29, the court issued an order denying EPA's motion to rehear the case. The denial cements the appellate court's ruling, remanding the issue back to EPA, and ordering the agency to conduct a new analysis of the Michigan facilities using physical proximity as the sole basis for determining adjacency. In response, EPA has stated that relying on physical proximity alone may lead both to "absurd results" and increased regulatory burdens under the NSR and PSD programs.[68] The agency announced that it plans to implement the 6th Circuit's ruling solely in the 6th Circuit states of Michigan, Ohio, Tennessee, and Kentucky.[69]

Contrary to this, source determinations for NESHAPs in the sector are clearly outlined in the CAA. In Section 112(n)(4), Congress specifically exempted upstream oil and gas operations from aggregation in several ways. First, with respect to the "major source" category, Section 112(n)(4) of the CAA provides that, notwithstanding the general definition of "major source,"

> emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.

Second, with respect to the "area source" category, Section 112(n)(4) provides that

> the Administrator shall not list oil and gas production wells (with its associated equipment) as an area source category under subsection (c), except that the Administrator may establish an area source category for oil and gas production wells located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of 1 million, if the Administrator determines that emissions of hazardous air pollutants from such wells present more than a negligible risk of adverse effects to public health.

At the time, the 101st Congress (1990) found that

> oil and gas wells, and associated equipment and gas processing, have generally very low emissions of air toxics. Furthermore, these operations are typically located in remote areas, with wells and equipment widely dispersed geographically, rather than concentrated in a

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[67] *Summit Petroleum Corp. v. EPA*, 6th Cir., Nos. 09-4348, 10-4572, 8/7/12.

[68] For example, the agency argues that the Summit ruling could actually lead to increased regulatory burdens under the NSR and PSD programs because permitting obligations are triggered by modifications at a source that result in net emission increases. Under the program, facilities can reduce emissions from another unit at that source to balance out emissions increases and avoid the trigger. EPA also says that relying on physical proximity alone will lead to "absurd results," saying that regulators as a result of the vacatur would have to consider a group of oil wells that are located near a series of gas wells and owned by the same operator to be one source although they emit different streams of pollutants.

[69] See "Applicability of the Summit Decision to EPA Title V and NSR Source Determinations," memorandum from Stephen Page, Director of the Office of Air Quality Planning and Standards, to Regional Administrators, December 21, 2012, http://cleanenergyreport.com/iwpfile.html?file=jan2013%2Fepa2013_0040.pdf.

> single area. For these reasons, it is very unlikely that oil and gas sources would present a significant risk to human health and it is not expected that this source category would need to be a listed category designated for regulation.[70]

In response, EPA wrote in the 1999 preamble that the definition of facility should "lead to an aggregation of emissions in major source determinations that is reasonable, consistent with the intent of the Act, and easily implementable." Consequently, EPA determined it was not appropriate to aggregate crude oil and natural gas facilities at that time.[71]

Measurement of Emissions

The 2012 federal air standards are based on EPA's emission estimates for the crude oil and natural gas sector. While emissions from certain activities and equipment lend themselves to credible estimates, others—specifically fugitive emissions from production activities such as hydraulically fractured well completions, flowback, and produced water ponds—are more difficult to evaluate, have fewer data available, and remain under considerable debate. Currently, the primary source of information on emissions from the sector is a methane study published in 1996 by EPA and the Gas Research Institute (GRI). EPA annually calculates industry emissions using the methodology derived from this report, and while many of the factors have been representative over the period of 1992 to the present, several have been recalculated due to new information. EPA's inventory has been criticized by industry groups and other sources, many of which have put forth competing, and sometimes conflicting, estimates over the past few years. At this time, a comprehensive national inventory that directly measures the quantity and composition of fugitive emissions from natural gas systems does not exist. Until there is an adequate and reliable assessment of industry-wide emissions, the benefits, costs, and basis for regulation may remain uncertain. In light of these considerations, Congress may examine ways in which to best facilitate more comprehensive and technically accurate emissions estimates.

By definition, "fugitive" emissions are those which are elusive and transitory. Thus, the single greatest difficulty in estimating emissions from natural gas systems is acquiring comprehensive and consistent measurement data. Currently, the most comprehensive study of emissions in the industry is more than a decade old, uses emissions factors and activity levels to calculate data, and focuses primarily on methane. EPA has initiated a more detailed inventory of the oil and gas sector's GHG emissions (i.e., methane and CO_2) under the agency's GHG Reporting Rule, and the first data for major sources were released in February 2013.[72] National emissions inventories for criteria and hazardous air pollutants, however, are distinct from GHG inventories and are complicated by the fact that concentrations of these chemicals vary geographically across resource reservoirs. A few states have begun the process of acquiring emissions inventories from

[70] Representative Jack Fields (R-TX-08), Conference Report on S. 1630, Clean Air Act Amendments of 1990 (House of Representatives - October 26, 1990), *Congressional Record*, vol. 136, p. H12868.

[71] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and National Emission Standards for Hazardous Air Pollutants: Natural Gas Transmission and Storage," 64 *Federal Register* 32610, June 17, 1999.

[72] See EPA's GHGRP 2011 data on the agency's website, http://www.epa.gov/ghgreporting/ghgdata/reported/petroleum.html.

upstream production activities (e.g., Texas,[73] Pennsylvania,[74] California,[75] and Colorado,[76] as well as a national survey to be conducted by the University of Texas at Austin),[77] but few have presented or harmonized this information. There are also many examples of local emissions inventories, commissioned by a range of stakeholders—from regional and municipal agencies to community groups and academic institutions. None are fully consistent with shared measurement practices and each use different techniques for their data collection. It is for these reasons that the first recommendation in the report released by the U.S. Secretary of Energy Advisory Board Shale Gas Production Subcommittee is to "immediately launch projects to design and rapidly implement measurement systems to collect comprehensive methane and other emissions data."[78]

Currently, the primary source of information on emissions in the natural gas industry is a methane study published in 1996 by EPA and the Gas Research Institute (GRI).[79] At the time, the EPA/GRI study was conducted to assess the GHG emissions from various U.S. industrial sectors to assist in data analysis for the Intergovernmental Panel on Climate Change and emissions reporting for U.S. commitments to the United Nations Framework Convention on Climate Change.[80] The study focuses on 1992 (as a base year) and uses three primary methodologies to generate emissions factors from over 100 different sources within the industry. The methods include (1) "component measurement," wherein emissions are measured directly from a large number of randomly selected pieces of equipment to determine an average emission factor for each type; (2) "tracer gas," wherein facility-wide emissions are calculated by releasing a tracer gas at a known and constant rate near the facility and measuring the downwind concentrations of the tracer and methane; and (3) "leak statistics," wherein emissions are measured for a large number of pipeline leaks to determine an average emissions rate per leak as a function of pipe material, age, operating pressure, and environmental characteristics. Total industry emissions are then estimated by multiplying these emissions factors by the activity levels for each system component (i.e., the

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[73] See Texas Commission on Environmental Quality, *Barnett Shale Special Inventory,* http://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/summarydatainfo.pdf.

[74] See Pennsylvania Department of Environmental Protection announced protocol, http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Long-Term_Marcellus_Ambient_Air_Monitoring_Project-Protocol_for_Web_2012-07-23.pdf.

[75] See California Environmental Protection Agency, Air Resources Board, *2007 Oil and Gas Industry Survey Results, Final Report,* December 2011, and other relevant documents on the ARB website, http://www.arb.ca.gov/cc/oil-gas/oil-gas.htm.

[76] See Colorado Department of Natural Resources press release, "State to undertake major study on oil and gas emissions," January 9, 2013, http://dnr.state.co.us/Media/Pages/PressReleases.aspx.

[77] The University of Texas at Austin, along with two environmental engineering firms, URS and Aerodyne Research, announced on October 10, 2012, the launch of a comprehensive study of methane emissions around gas wells. Researchers are to focus on gas production sites in the Marcellus, Eagle Ford, Haynesville, Barnett, Fayetteville, and Niobrara shale formations. Nine oil and gas companies have agreed to allow sampling teams onto their sites: Anadarko Petroleum Corp., BG Group PLC, Chevron Corp., Encana Oil & Gas (USA) Inc., Pioneer Natural Resources Co., Shell Oil Co., Southwestern Energy, Talisman Energy and XTO Energy, a subsidiary of Exxon Mobil Corp. The announced study is part of a broader five-part investigation to measure methane leakage across the natural gas supply chain, http://www.utexas.edu/news/2012/10/10/university-of-texas-at-austin-study-measures-methane-emissions-released-from-natural-gas-production/.

[78] Secretary of Energy Advisory Board Shale Gas Production Subcommittee, *Shale Gas Production Subcommittee 90-Day Report*, p.16.

[79] Gas Research Institute and U.S. Environmental Protection Agency, *Methane Emissions from the Natural Gas Industry, Volumes 1-15*, GRI-94/0257 and EPA 600/R-96-080, June 1996.

[80] UNFCCC, Treaty Number: 102-38, October 7, 1992, the resolution of advice and consent to ratification agreed to in the Senate by Division Vote. For more discussion of U.S. commitments, see CRS Report R40001, *A U.S.-Centric Chronology of the International Climate Change Negotiations*, by Jane A. Leggett.

number of wellheads, compressors, processing plants, miles of pipeline in operation, and other components) across the entire industry. The EPA/GRI study estimates that the industry emitted 314 ± 105 billion standard cubic feet (bscf) of methane in 1992 (i.e., 127 ± 42 million metric tons of carbon dioxide equivalent [$MMtCO_2e$], or 1.42% ± 0.47% of the industry's gross national production that year).[81] Roughly 60% of the industry's methane emissions are estimated to be from fugitive sources, about 30% from venting, and about 8% from combustion. Results of the EPA/GRI study, by source categories, are reported in **Table 1**.

EPA annually calculates emissions estimates for the industry using the methodology from the 1996 EPA/GRI study. Since its publication, activity data for some of the components in the system have been updated based on publicly available information. For other sources where annual activity data are not available or have not been reported by industry, EPA has developed a set of industry activity factor drivers to assist in modeling. While many of the emissions factors modeled by the EPA/GRI study were considered representative over the period of 1992 to the present, several factors have been re-calculated since publication. Most notably, emissions factors for gas well cleanups, condensate storage tanks, and centrifugal compressors have been revised due to new information. Emissions factors for gas well completions in unconventional resources with hydraulic fracturing—which were not industry practice at the time of the EPA/GRI study—have also been added to the inventory. With these revisions, EPA estimates that the industry emitted 247.7 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) greenhouse gases in 2010, of which 215.4 $MMtCO_2e$ was methane (i.e., 532 bscf of methane, or 2.4% of the industry's gross national production that year).[82]

Table 1. Methane Emissions in the U.S. Natural Gas Industry

For the base year 1992

Source		Annual Methane Emissions (Bscf)	% of Total
Fugitive Emissions	**Subtotal**	**195.3**	**62.1**
Equipment Leaks			
Production Facilities		17.4	5.5
Gas Plants		24.4	7.8
Compressor Stations (transmission and storage)		67.5	21.5
Metering and Pressure Regulating Stations		31.8	10.1
Customer Meter Sets		5.8	1.8
Underground Pipeline Leaks (all segments)		48.4	15.4
Vented Emissions	**Subtotal**	**94.2**	**30.0**
Pneumatic Devices		45.7	14.6

[81] 314 bscf of methane is equivalent to approximately 127 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) greenhouse gases, using the conversion 1000 bscf CH_4 = 0.4045 $MMtCO_2e$ at 60 degrees Fahrenheit (15.6 degrees Celsius) and either 14.696 psi (1 atm or 101.325 kPa) or 14.73 psi (30 inHg or 101.6 kPa) of pressure.

[82] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010*, Washington, DC, EPA 430-R-12-001, April 15, 2012, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf. Conversion factor of 1000 bscf CH_4 = 0.4045 $MMtCO_2e$ at 60 degrees Fahrenheit (15.6 degrees Celsius) and either 14.696 psi (1 atm or 101.325 kPa) or 14.73 psi (30 inHg or 101.6 kPa) of pressure. The U.S. Energy Information Administration reports 2010 U.S. natural gas marketed production as 22,402 bscf, see http://www.eia.gov/dnav/ng/hist/n9050us2a.htm.

Source		Annual Methane Emissions (Bscf)	% of Total
Blow and Purge		30.2	9.6
Dehydrator Glycol Pumps		11.1	3.5
Dehydrator Vents		4.8	1.5
Chemical Injection Pumps		1.5	0.5
Other		0.9	0.3
Combusted Emissions	**Subtotal**	**24.9**	**7.9**
Compressor Exhaust		24.9	7.9
	Total	**314.0**	**100.0**

Source: David A. Kirchgessner et al., *Estimate of Methane Emissions from the U.S. Natural Gas Industry*, U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, Research Triangle Park, NC, 1996, p. 12.

Notes: Emissions from meter and pressure regulating stations result from both pneumatic and fugitive emissions. Since these components cannot be separated using the tracer measurement method, emissions are shown as fugitive by default.

The emissions estimates EPA uses for hydraulically fractured well completions and re-completions come from data provided by industry sources at several EPA Natural Gas STAR technology transfer workshops between 2004 and 2007.[83] Using the reported data in its 2010 Background Technical Support Document, *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry*,[84] EPA creates separate categories for conventional and unconventional well completions, and increases its estimate of methane emissions from both categories from 0.02 metric tons per well completion to 0.71 metric tons per conventional well and 177 metric tons per unconventional well (or 37 thousand cubic feet [Mcf]/completion and 9,175 Mcf/completion respectively). EPA assumes a 3-10 day flowback period with an uncontrolled release of methane. Further, EPA assumes that 51% of the fugitive emissions from hydraulically fractured well completions are flared—and the rest vented—based upon state and local regulations for control devices that are currently in place.

EPA's methodology for estimating methane emissions from hydraulically fractured well completions has been criticized by a number of sources. A detailed critique of EPA's numbers can be found in IHS CERA's 2011 report, *Mismeasuring Methane: Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development.*[85] CERA's main concerns involve the small

[83] The figures were drawn from four studies over two workshops that included data from over 1,000 wells completed between 2002 and 2006. U.S. Environmental Protection Agency, "Green Completions," Natural Gas STAR Producers' Technology Transfer Workshop, September 21, 2004, and U.S. EPA, "Reducing Methane Emissions During Completion Operations," Natural Gas STAR Producers' Technology Transfer Workshop, September 11, 2007. The presentations included a Devon case study from the Fort Worth Basin (30 wells, 11,900 Mcf/completion), a Williams case study from the Piceance Basin (1,064 wells, 24,449 Mcf/completion), a Weatherford coal bed methane case study (3 wells, 667 Mcf/completion), and a nationwide industry data set (106 wells, 5,820 Mcf/completion). For more on the EPA Natural Gas STAR program, see http://www.epa.gov/gasstar/.

[84] U.S. Environmental Protection Agency, *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document*, Climate Change Division, Washington, DC, 2010, http://www.epa.gov/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf.

[85] IHS CERA estimates methane emissions from the oil and gas "production" sector to be 43 $MMtCO_2e$ as opposed to EPA's estimate of 130 $MMtCO_2e$ from "field production." See Mary Barcella, Samantha Gross, and Surya Rajan, *Mismeasuring Methane: Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development*, IHS CERA,

sample size for emissions data and the unsupported assumptions on venting practices. Further, several industry sources have reported competing emissions estimates, including the American Petroleum Institute and the America's Natural Gas Alliance (which list total industry emissions at half of EPA's estimate due to a re-calculation of emissions factors and activity levels for liquids unloading[86] and re-fractured well completions),[87] URS (which estimates emissions of 765 Mcf of gas on a per well basis compared to EPA's 9,175 Mcf),[88] and Devon Energy Company (which reports data from eight of its operators demonstrating that flowback periods last on average only 3.5 days compared to EPA's estimated 3-10 days).[89] As with any self-selected and self-reported survey, it is difficult to determine how representative these samples are of overall industry practice.

Other published studies use different methodologies for the calculation of leakage (e.g., satellite observations, ambient measurements, and dispersion modeling). A National Oceanographic and Atmospheric Administration (NOAA) study analyzes daily air samples collected at the Boulder Atmospheric Observatory in Weld County in northeastern Colorado and concludes that fugitive natural gas emissions from drilling operations range from 2.3% to 7.7% of industry's gross annual production.[90] The study uses an extensive data set of ambient concentrations of methane and related hydrocarbons in the vicinity of oil and gas operations in the region, along with the known emissions profiles for these gases from oil and gas operations, to infer the emissions from the industry. In December 2012, the research team reported updated Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage at 9% of the total production.[91]

On February 5, 2013, the industry-reported dataset for GHG emissions collected under EPA's Greenhouse Gas Reporting Program (GHGRP) was released for the first time for crude oil and natural gas systems.[92] The data show 2011 GHG emissions from over 1,800 facilities in the crude

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Private Report, Cambridge, MA, 2011, http://press.ihs.com/press-release/recent-estimates-greenhouse-gas-emissions-shale-gas-production-are-likely-significantl.

[86] "Liquids unloading" is a maintenance activity in depleted conventional reservoirs where water produced with the gas has accumulated to the point where it stops gas flow. In order to reestablish gas flow, the well is blown to the atmosphere, causing the vented release of emissions. The 2011 GHG Inventory has this category listed for contributing approximately 34% of all methane emissions from the natural gas industry for that year.

[87] Terri Shires and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses,* Final Report, June 1, 2012, http://www.api.org/news-and-media/news/newsitems/2012/oct-2012/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf. The authors present data reported by over 20 of their industry partners from over 91,000 wells (or 20% of known wells in operation) demonstrating that a re-calculation of two of EPA's source categories—liquids unloading and unconventional gas re-fracture rates—returned a 50% reduction in industry emissions compared to EPA's estimate. The study did not report any new estimates for the quantity of emissions from hydraulically fractured well completions or re-completions, only estimates on the rates of re-fracture.

[88] URS, "Gas Well Completion Data," Attachment 3 of the American Exploration and Production Council and America's Natural Gas Alliance, *Comments – Proposed Rule – Oil and Natural Gas Sector Consolidated Rulemaking, NSPS and NESHAP Reviews,* November 30, 2011, http://epa.gov/quality/informationguidelines/documents/12003-attB.pdf.

[89] Darren Smith, Devon Energy Corporation, Testimony before the Senate Environment and Public Works Subcommittee on Clean Air and Nuclear Safety, Washington, DC, June 19, 2012, http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=5a14d73e-36d6-4f5b-8985-98a506e3cbab.

[90] Gabrielle Pétron et al., "Hydrocarbon Emissions Characterization in the Colorado Front Range: A Pilot Study," *Journal of Geophysical Research,* vol. 117 (2012).

[91] As reported by Jeff Tollefson, "Methane leaks erode green credentials of natural gas," *Nature,* 493:12, January 2, 2013, http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123#auth-1.

[92] See EPA's GHGRP 2011 data on the agency's website, http://www.epa.gov/ghgreporting/ghgdata/reported/

oil and natural gas sector, including production, processing, transmission, and distribution. In total, these facilities accounted for GHG emissions of 225 $MMtCO_2e$. Of note in the reporting: (1) The crude oil and natural gas sector is the second-largest stationary source of U.S. GHG emissions, behind power plants; (2) CO_2 emissions from the crude oil and natural gas sector account for 142 $MMtCO_2e$, and methane emissions account for 83 $MMtCO_2e$; (3) Onshore crude oil and natural gas production is the largest contributor, covering approximately 41% of reported emissions; (4) Emissions from onshore production facilities are primarily methane (such as leaks from equipment and vented emissions) while emissions from natural gas transmission and processing facilities are primarily CO_2 (such as combustion emissions associated with compressors); and (5) While the total emissions of CO_2e reported by industry is consistent with the total emissions previously reported by EPA's national inventory, the ratio of CO_2 to methane emissions is notably different, with more CO_2 (and less methane) reported by the industry than estimated by EPA. The agency has instituted a multi-step data verification process for the GHGRP and intends to review the data on an ongoing basis, anticipating that the overall data quality will increase over time as facilities become familiar with the calculation methods and begin using more direct measurement.

Using the data reported by industry under comments to the 2012 air standards as well as under the GHG Reporting Program, EPA again revised its calculations for the sector in its *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, released April 15, 2013.[93] For the 2011 inventory, EPA revisits its calculations for liquid unloading—the process of flushing excess water from a drilling well which the agency had estimated contributed as much as 51% of the total CH_4 emissions from the sector (an estimate that was disputed by many industry operators) and makes other changes, including its count of the number of active wells and its methodology for estimating emissions from hydraulic fracturing and refracturing well completions. With these revisions, EPA estimates that the industry emitted 177.0 $MMtCO_2e$ greenhouse gases in 2011, of which 144.7 $MMtCO_2e$ was methane (i.e., 358 bscf of methane, or 1.5% of the industry's gross national production that year).

As debate continues over the level of methane emissions from natural gas production activities, a full assessment of VOCs, HAPs, hydrogen sulfide, and other aromatic hydrocarbons becomes even more complicated, since the concentrations of these chemicals can vary greatly from reservoir to reservoir. Thus, an accurate assessment of the levels of VOCs, SO_2, and HAPs emissions from various production activities would require not only an accurate measurement of natural gas emissions but a full accounting of the component compositions of the gas across the geographic variability of the resource.

Impacts of Emissions

The 2012 federal air standards are based on EPA's expectations that the avoided emissions under the rules would result in improvements in air quality and reductions in health effects associated with exposure to HAPs, ozone, and methane. However, the relationship between air pollution from natural gas systems and its impacts on human health and the environment has never been fully quantified and assessed. EPA acknowledges this shortcoming in the rule's proposal, stating that a full quantification of health benefits for the 2012 standards could not be accomplished due

petroleum.html.

[93] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, Washington, DC, EPA 430-R-13-001, April 15, 2013, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf.

to the “unavailability of data and the lack of published epidemiological studies correlating crude oil and natural gas production to respective health outcomes.”[94] Various stakeholders assert that the lack of published and peer-reviewed literature makes it challenging to scientifically assess the impacts of natural gas operations. Some contend that this uncertainty argues against additional pollution controls at this time. Others maintain that the relevant question for determining whether pollution controls are necessary is whether natural gas systems impact an area’s ability to attain air quality standards (NAAQS). In light of these considerations, Congress may wish to evaluate whether existing requirements are adequate to address concerns over the human health and environmental impacts of oil and gas activities, or, if different requirements are necessary.

Quantifying the extent to which crude oil and natural gas systems contribute to air pollution is a complicated task, due in part to the difficulties in modeling the direct and indirect impacts of emissions reductions from a single industrial sector on the greater environment. Although there are many different methodologies that can be used to assess emissions from the industry, each is burdened with unique disadvantages.[95] Thus, while science has demonstrated that emissions of VOCs and NO_x contribute to the generation of ground-level ozone (i.e., smog), emissions of various organic air toxics can pose a threat to human health, and emissions of methane produce ground-level ozone and force climate change, comprehensive epidemiological studies correlating the emissions from natural gas systems to specific long-range and cumulative health outcomes are virtually nonexistent. It should be noted that such studies are generally difficult, rare, and expensive to conduct, requiring data that are typically absent or inadequate for assessment (e.g., precise and accurate estimates of emissions, fate and transport, and exposure levels, as well as impacts data on relatively large populations of exposed individuals over long durations of time). More common, instead, are localized studies or anecdotal reports—by stakeholders who live and work near oil and gas operations—of general air quality issues such as haze, odor, or ill health. These studies are countered by industry and/or agency reports that present information on recommended practices, regulatory compliance, and a history of monitored and reported environmental stewardship.

Various stakeholders assert that the lack of published and peer-reviewed literature makes it challenging to scientifically assess the impacts of oil and gas drilling operations. The Centers for Disease Control and Prevention warns that the science on the impacts of natural gas drilling on health and the environment is “not yet clear,” stating that there is “not enough information to say with certainty whether shale gas drilling poses a threat to public health,” and that “more research is needed for us to understand public health impacts from natural gas drilling and new gas drilling

[94] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry*, Research Triangle Park, NC, July 2011, p. 4-1.

[95] Scientists typically use two different methods when trying to understand how a given air pollution source affects local air quality. One approach is to conduct ambient air monitoring, which directly measures air pollution levels that people breathe. However, in using this method, the presence of a pollutant likely reflects contributions from many different sources, such as motor vehicles, gasoline stations, and industrial plants. Another approach is to use dispersion modeling, which estimates air pollution levels using models that predict how pollutants move through the air from the point where they are released. However, in using this method, measurements of the initial outputs must be completed and verified in order to make accurate dispersion assessments. Satellite modeling and direct component measurements are other ways of quantifying emissions. These top-down and bottom-up approaches to assessments also have their specific drawbacks, including source attribution and data availability.

technologies."[96] Similarly, a recent report by GAO[97] examines the available studies of air quality at shale gas development sites and finds that they are "generally anecdotal, short-term, and focused on a particular site or geographic location." Thus, they "do not provide the information needed to determine the overall cumulative effect that shale oil and gas activities have on air quality." GAO concludes that "the cumulative effect shale oil and gas activities have on air quality will be largely determined by the amount of development and the rate at which it occurs, and the ability to measure this will depend on the availability of accurate information on emission levels. However ... data on the severity or amount of pollutants released by oil and gas development, including the amount of fugitive emissions, are limited." It is for these reasons that the final recommendation in the report released by the U.S. Secretary of Energy Advisory Board Shale Gas Production Subcommittee is to advise federal, regional, state, and local jurisdictions "to place greater effort on examining [the] cumulative impacts" from "drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities [which] can overwhelm ecosystems and communities."[98]

Some federal, state, and local agencies have embarked upon or are considering further investigation into the human health and environmental impacts of oil and gas production. These include the U.S. Department of Health and Human Services, and the states of Colorado[99] and Maryland,[100] among others. Examples of published studies on the human health and environmental impacts of oil and gas production are as follows:

Ozone

Many studies report that at each stage of natural gas production, VOCs—including BTEX and other hydrocarbons—and methane can escape and mix with nitrogen oxides from the exhaust of diesel-fueled equipment, and, in the presence of sunlight, produce ground-level ozone (i.e., smog). Several areas of the country with heavy concentrations of drilling suffer from serious ozone problems.

For example, new oil and gas development has begun across sections of the Rocky Mountains that may be connected to the rise in ozone pollution. A 2005 Western Governors' Association report finds that crude oil and natural gas production operations released more than 430,000 tons of VOCs in Colorado, New Mexico, Utah, Wyoming, and Montana in 2002. The report projects that operations in these states would more than double their VOCs emissions in 15 years,

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[96] Comments by Dr. Christopher Portier, head of CDC's National Center for Environmental Health and Agency for Toxic Substances and Disease Registry (ATSDR), as covered on January 5, 2012, by Kevin Begos of the Associated Press quoting excerpts of an email. Publication of the full text of the email, as released by the CDC press office, can be found at http://www.slopefarms.com/2012/01/08/shale-gas-drilling-and-public-health-first-publication-of-full-text-email-on-public-health-risks-of-from-cdcs-national-center-for-environmental-health-and-agency-for-toxic-substances-and-dis/.

[97] U.S. Government Accountability Office, *Oil and Gas: Information on Shale Resources, Development, and Environmental and Public Health Risks*, GAO-12-732, September 2012, pp. 33-37, http://www.gao.gov/assets/650/647791.pdf.

[98] Secretary of Energy Advisory Board Shale Gas Production Subcommittee, *Shale Gas Production Subcommittee 90-Day Report*, p.25. For example, as a part of New York state's ongoing review of hydraulic fracturing, the New York State Department of Environmental Conservation (NY DEC) has asked New York State Department of Health (NY DOH) to undertake a review of the NY DEC health impact analysis, see http://www.dec.ny.gov/press/85071.html.

[99] See Colorado Department of Public Health and the Environment news release, "State to undertake major study on oil and gas emissions," January 9, 2012, http://www.colorado.gov/cs/Satellite/CDPHE-Main/CBON/1251590280071.

[100] See Maryland, Department of the Environment, Marcellus Shale Safe Drilling Initiative Study: Part I (December 2011), http://www.mde.state.md.us/programs/Land/mining/marcellus/Pages/index.aspx.

releasing more than 965,000 tons annually by 2018.[101] This release would equal the average amount of VOCs emitted annually from approximately 50,000 gas stations or by more than 25 million passenger cars, each driven 12,500 miles.[102] A 2008 analysis by the Colorado Department of Public Health and Environment concludes that smog forming emissions from Colorado's crude oil and natural gas operations exceed vehicle emissions for the entire state.[103] In 2009, the governor of Wyoming recommended that the state designate Wyoming's Upper Green River Basin as an ozone nonattainment area.[104] An extended assessment by the Wyoming Department of Environmental Quality finds the state's ozone pollution problems are "primarily due to local emissions from oil and gas ... development activities: drilling, production, storage, transport, and treating."[105] Recently, northeastern Utah recorded unprecedented ozone levels in the Uintah Basin, with more than 68 exceedances of the federal health standard during the first three months of 2010, and over 24 exceedances during the winter of 2011.[106] The Bureau of Land Management identifies oil and gas activities in the region as the primary cause of the ozone pollution.[107] Further, a 2009 study concludes that numerous "Class I areas" in the Rocky Mountain region—a designation reserved for national parks, wilderness areas, and other such lands—are likely to be impacted by increased ozone pollution as a result of oil and gas development, including Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico. These areas are all near concentrated oil and gas development in the San Juan Basin.[108] However, the evidence linking oil and gas development directly to high ozone levels in the region remains inconclusive. Researchers caution that many factors can contribute to the Rocky Mountains' ozone problems. For example, uniform snow cover reflects and concentrates sunlight, boosting ozone levels, as do temperature inversions that trap pollutants in mountain basins.[109] In support of this point, the interim findings of the *2012 Uintah Basin Winter Ozone & Air Quality Study,* released in August 2012, report that there were no

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[101] Russell and Pollack, *Oil and Gas Emission Inventories for the Western States,* Environ International Corporation study prepared for the Western Governors' Association, December 27, 2005, http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf.

[102] See EPA Clearinghouse for Inventories and Emissions Factors, *Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources,* January 1995, http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s02.pdf.

[103] Colorado Dept. of Public Health & Environment, Air Pollution Control Division, *Oil and Gas Emission Sources Presentation for the Air Quality Control Commission Retreat,* May 15, 2008, at pages 3-4.

[104] See Letter from Wyoming Governor Dave Freudenthal to Carol Rushin, Acting Regional Administrator, USEPA Region 8, (Mar. 12, 2009) ("Wyoming 8 - Hour Ozone Designation Recommendations"), http://deq.state.wy.us/out/downloads/Rushin%20Ozone.pdf.

[105] Wyoming Department of Environmental Quality, *Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin,* March 26, 2009 ("Wyoming Nonattainment Analysis"), http://deq.state.wy.us/out/downloads/Ozone%20TSD_Outside%20UGRB%20%282%29.pdf.

[106] Randal Martin, et al., *Final Report: Uinta Basin Winter Ozone and Air Quality Study, December 2010-March 2011,* Energy Dynamics Laboratory, Utah State University, for Uintah Impact Mitigation Special Service District, June 14, 2011, http://rd.usu.edu/files/uploads/ubos_2010-11_final_report.pdf.

[107] BLM, *GASCO Energy Inc. Uinta Basin Natural Gas Development Draft Environmental Impact Statement* ("GASCO DEIS"), p. 3-13, http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_/gasco_energy_eis.html.

[108] Marco Rodriguez, et al., "Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States," *Journal of the Air and Waste Management Association,* 111 (Sept. 2009), http://www.wrapair.org/forums/amc/meetings/091111_Nox/Rodriguez_et_al_OandG_Impacts_JAWMA9_09.pdf.

[109] See comments made by Keith Guille, spokesman for Wyoming DEQ, in Charles W. Schmidt, "Blind Rush?: Shale Gas Boom Proceeds amid Human Health Questions," *Environmental Health Perspectives,* vol. 119, no. 8 (August 2011), p. A352.

exceedances of the eight-hour ozone standard for the basin in 2012, even though higher levels of ozone precursors and VOCs were measured in the region (the lack of sunlight-reflecting snowpack in 2012 is suggested as a possible reason).[110]

As another example, the Dallas-Fort Worth area in Texas is home to substantial oil and gas development. Of the nine counties surrounding the Dallas-Fort Worth area that EPA has designated as "nonattainment" for ozone, five contain significant oil and gas development.[111] A 2009 study finds summertime emissions of smog-forming pollutants from oil and gas operations in the Dallas-Fort Worth area exceed emissions from all motor vehicles in the area.[112] A 2012 study finds that emissions from natural gas compressor stations and flares contribute to significant amounts of ground-level ozone and formaldehyde in the Dallas-Fort Worth area, estimating that a single natural gas processing facility in the Barnett shale area could add as much as 3 parts per billion (ppb) to the hourly average ambient ozone.[113] Still, the evidence linking oil and gas development directly to high ozone levels in the region remains inconclusive. In 2009 and 2010, the Texas Commission on Environmental Quality (TCEQ) conducted several large, in-depth surveys of air quality in the six counties surrounding Fort Worth. The TCEQ study identifies a 15% drop in the 8-hour ozone design value, despite a 10-fold increase in natural gas production in the region over the past decade. TCEQ attributes at least part of this reduction to the state's NO_x control strategies as well as the prevailing winds.[114]

Air Toxics

Other studies (e.g., epidemiological studies) focus on the human health impacts of hazardous air pollutants (HAPs) known or suspected to be released by crude oil and natural gas operations. A 2011 survey of existing literature on the topic reported that of the known chemicals used and/or found in natural gas operations, approximately 37% of the chemicals are volatile and may become airborne. The study further noted that if exposures exceed certain levels, over 89% of these chemicals can harm the eyes, skin, sensory organs, respiratory tract, gastrointestinal tract, or liver; 81% can cause harm to the brain and nervous system; 71% can harm the cardiovascular system and blood; and 66% can harm the kidneys. Overall, the hazardous air pollutants produce a profile that displays a higher frequency of health effects than the water soluble chemicals. In addition, because they vaporize, not only can they be inhaled, but they can be ingested or absorbed through the skin, increasing the chance of exposures.[115]

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[110] See *2012 Uintah Basin Winter Ozone & Air Quality Study-Summary of Interim Findings, Ongoing Analyses, and Additional Recommended Research,* August 7, 2012, at http://op.bna.com/env.nsf/id/smiy-8x9rv3/$File/UintahWinter.pdf.

[111] Texas Railroad Commission, http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf.

[112] Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements,* January 26, 2009, http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf. It should be noted that Al Armendariz is the former EPA Region 6 Administrator who resigned on April 30, 2012, after remarks made in 2010 regarding EPA's enforcement policy.

[113] Eduardo P. Olaguer, "The Potential Near-source Ozone Impacts of Upstream Oil and Gas Industry Emissions," *Journal of the Air & Waste Management Association*, vol. 62, no. 8 (2012), http://www.tandfonline.com/doi/abs/10.1080/10962247.2012.688923.

[114] Texas Commission on Environmental Quality, "A Commitment to Air Quality in the Barnett Shale," *Natural Outlook Newsletter*, Fall 2010, http://www.tceq.state.tx.us/publications/pd/020/10-04/a-commitment-to-air-quality-in-the-barnett-shale.

[115] Theo Colborn, Carol Kwiatkowski, Kim Schultz, Mary Bachran, "Natural Gas Operations from a Public Health Perspective," *Human and Ecological Risk Assessment*, vol. 17, no. 5, 2011, pp. 1039-1056, http://www.endocrinedisruption.com/chemicals.journalarticle.php.

Several studies report that sources of HAPs in the oil and gas industry may be numerous. Data from the State of Colorado suggest that there may be more than 26 individual sources of HAPs in the oil and gas sector, including "venting, dehydration, gas processing, compression, leaks from equipment (fugitive emissions), open-pit waste ponds, and land application of volatile wastes."[116] A study of HAPs emissions from natural gas related sources within the city of Fort Worth, TX, documents the following for HAPs emissions: 0.02 to 2 tons per year (tpy) from well pads (including emissions from equipment leaks, produced water and condensate storage and loading, and lift compressors); 0.9 to 8.8 tpy from well pads with compressors; 10 to 25 tpy from compressor stations (including emissions from combustion at the compressor engines or turbines, equipment leaks, storage tanks, glycol dehydrators, flares, and condensate and/or wastewater loading); 47 tpy on average from processing facilities (including emissions from equipment leaks, storage tanks, separator vents, glycol dehydrators, flares, condensate and wastewater loading, compressors, amine treatment and sulfur recovery units); and 0.4 tpy on average from saltwater treatment facilities.[117]

Although oil and gas development generally has not occurred in densely populated areas, this is not always the case, particularly with respect to recent expansion in unconventional resources. Several local, state, and national health agencies have expressed concerns about the health impacts of HAPs emissions from oil and gas facilities, including the Center for Disease Control and Prevention (CDC),[118] the Agency for Toxic Substances and Disease Registry (ATSDR),[119] the Association of Occupational and Environmental Clinics (AOEC) and the Pediatric Environmental Health Specialty Unit (PEHSU),[120] the Colorado School of Public Health,[121] the Town of Dish, Texas,[122] the City of Fort Worth, Texas,[123] and the City of Houston, Texas.[124] In particular, the ATSDR investigation was spurred by community health complaints such as dizziness, nausea, respiratory problems, and eye and skin irritation to more severe concerns including cancer. The investigation identifies elevated cancer risk at one site and recommends further investigation into HAPs emissions and risks at all the sites. Similarly, the Colorado School of Public Health identifies air pollution from the crude oil and natural gas activities as contributing to acute and

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[116] Amy Mall et al., *Drilling Down: Protecting Western Communities from the Health and Environmental Effects of Oil and Gas Production,* NRDC, October 2007, (citing CDPHE data), http://www.nrdc.org/land/use/down/down.pdf

[117] Eastern Research Group, *City of Fort Worth Natural Gas Air Quality Study,* 2011, at http://fortworthtexas.gov/gaswells/?id=87074.

[118] Comments by Dr. Christopher Portier, CDC, *op cit.*

[119] ATSDR, *Health Consultation: Public Health Implications of Ambient Air Exposures to Volatile Organic Compounds as Measured in Rural, Urban, and Oil & Gas Development Areas Garfield County, Colorado,* 2008, http://www.cdphe.state.co.us/dc/ehs/GarfieldCounty.pdf.

[120] PEHSU, *Information on Natural Gas Extraction and Hydraulic Fracturing for Health Professionals*, 2011, http://aoec.org/pehsu/documents/hydraulic_fracturing_and_children_2011_health_prof.pdf.

[121] Roxana Witter, et al., *Draft Health Impact Assessment for Battlement Mesa, Garfield County, Colorado,* Colorado School of Public Health, 2011, http://www.garfield-county.com/index.aspx?page=1408; Lisa McKenzie, et al., *Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources,* Colorado School of Public Health, 2012, http://www.energyindepth.org/wp-content/uploads/2012/03/McKenzie-CSPH-Study-02-10-2012.pdf.

[122] Wolf Eagle Environmental, *Town of DISH, Texas Ambient Air Monitoring Analysis Final Report,* 2009, http://townofdish.com/objects/DISH_-_final_report_revised.pdf.

[123] Eastern Research Group, *City of Fort Worth Natural Gas Air Quality Study,* 2011, at http://fortworthtexas.gov/gaswells/?id=87074.

[124] Barbara Zielinska, Eric Fujita, Dave Campbell, *Monitoring of Emissions from Barnett Shale Natural Gas Production Facilities for Population Exposure Assessment. Houston TX,* Desert Research Institute, 2011, http://www.sph.uth.tmc.edu/mleland/attachments/Barnett%20Shale%20Study%20Final%20Report.pdf.

chronic health problems for those living near natural gas drilling sites, stating that "exposures to air pollutants during well completion activities present the greatest potential for health effects."[125] The CSPH analysis, based on three years of monitoring, finds a number of air toxics near the wells including benzene, toluene, ethylbenzene, and xylene.

However, critics have taken issue with the Colorado School of Public Health and other studies for a number of reasons including the use of (1) out of date data, (2) unrealistic estimates of emissions from sources, (3) overly conservative risk assessments when viewed in context, and (4) poor study design and input assumptions (e.g., the use of ambient collection methodology in a region populated with other emission sources such as roads, highways, and other industries).[126] In support of this point, other studies have reported little or no health effects from the sector. For example, in 2012, the Houston-based Plains Exploration and Production Company (PXP) released a report that said hydraulic fracturing operations at the Inglewood oil field in the Baldwin Hills area in Los Angeles County posed "no public health or environmental threats."[127] Similarly, in a review of health studies conducted by the Energy Institute at the University of Texas at Austin and published in February 2012, the authors conclude that "none of the studies reviewed ... showed a clear link between shale gas activities and documented adverse health effects, [and] that the gas industry has been using hydraulic fracturing for over 50 years, but the studies examined ... did not find any direct evidence for health impacts on workers in the industry or the public living near oil and gas industry activity."[128] Further, many industry sources have argued that the standards promulgated under the 1999 Crude Oil and Natural Gas Production NESHAPs have demonstrated protection of public health with an ample margin of safety.[129] Critics of EPA's regulatory requirements for air toxics have also expressed concern with the agency's decision to make significant and substantive changes to the agency's residual risk procedures, changes which they assert result in risk estimates between 100 and 1,000 times higher than actual. The contested procedures include (1) the consideration of risk from the total facility, (2) the consideration of risk across selected social, demographic, and economic groups within the population living near the facility, (3) the consideration of the hypothetical risk associated with the level of emissions allowed by the MACT standard, and (4) unreasonable assumptions concerning exposure points, times, and durations.

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[125] McKenzie, et al., *op cit.*

[126] Comments critical of the CSPH reports can be found at the Energy In Depth blog, http://www.energyindepth.org/non-elite-eight-worst-inputs-used-in-new-colorado-health-study/.

[127] Cardno Entrix, *Hydraulic Fracturing Study: PXP Inglewood Oil Field*, Prepared for Plains Exploration & Production Company, Los Angeles, CA, October 10, 2012, http://www.inglewoodoilfield.com/res/docs/102012study/Hydraulic%20Fracturing%20Study%20Inglewood%20Field10102012.pdf.

[128] Charles G. Groat and Thomas W. Grimshaw, *Fact-Based Regulation for Environmental Protection in Shale Gas Development*, The Energy Institute, The University of Texas at Austin, Austin, TX, February 2012, p. 30. It should be noted that in July 2012, the objectivity of The Energy Institute study was called into question by the Public Accountability Initiative. Officials at the University of Texas commissioned an outside review of the study and have since expurgated the findings.

[129] For an example of industry responses, see the comments to "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," submitted by Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute, November 30, 2011, accessed on http://www.regulations.gov. API asserts that establishing new and more stringent standards would be "patently unreasonable and cannot be justified ... because the so-called regulatory 'gaps' in the current rules clearly are not contributing to unacceptable risk," and that EPA's 2012 NESHAPs are "regulation for the sake of regulation and, as such, contradict Congress's clear intent that an ample margin of safety is an appropriate stopping point for emissions limitations under § 112" of the CAA. Industry's (and others') comments were incorporated into the final rules, and the revisions are reflected and discussed in EPA's "Summary of Key Changes to the Rules" Fact Sheet, at http://www.epa.gov/airquality/oilandgas/pdfs/20120417changes.pdf.

Greenhouse Gases

Finally, other studies focus on the impact of greenhouse gas emissions from crude oil and natural gas operations. Many of these studies advocate for the increased production and use of natural gas as a substitute for other fossil fuel resources because it is domestically available, economically recoverable, and considered a potential "bridge" fuel to a less polluting and lower GHG-intensive economy. However, when fugitive emissions of methane from all sectors of the industry are factored into the total life-cycle assessment of the resource,[130] the advantage of natural gas over other fossil fuels is less clear. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011* (published April 15, 2013) estimates natural gas systems emitted 144.7 million metric tons of carbon dioxide equivalent (MMtCO_2e) of methane in 2011, a 10% decrease from 1990 emissions, and 32.3 MMtCO_2e of non-combustion CO_2 in 2011, a 14% decrease from 1990 emissions. EPA cites improvements in management practices and technology, along with the replacement of older equipment, as helping to stabilize emissions of CO_2. The decrease in methane emissions is the result of a decrease in emissions from transmission and storage due to increased voluntary reductions and a decrease in distribution emissions due to a decrease in unprotected pipelines.[131] However, natural gas systems in 2011 were cited as being the single largest contributor to U.S. anthropogenic (i.e., man-made) methane emissions, representing nearly 25% of the total methane emissions from all domestic sources and accounting for about 2% of all GHG emissions in the United States. Some recent studies (outlined below) argue that expanding the production and use of natural gas could actually exacerbate rather than help mitigate global warming because methane's global warming potential (GWP)[132] is as much as 20—if not 50—times more potent than carbon dioxide, depending upon the time interval used to express warming impacts. These studies suggest that if significant amounts of methane were to leak during the production of natural gas, the climate forcing of methane could cancel out or even outweigh any benefit gained from switching away from oil or coal combustion processes.

Many of the published and publicly available life-cycle GHG emissions assessments of natural gas rely on the 1996 EPA/GRI emissions factors for methane leakage in the industry. EPA's recently updated emissions estimates suggest that leakage from natural gas systems is approximately 1.5% of gross national production.[133] EPA has neither calculated nor stated whether these revisions negate the apparent advantage natural gas has over oil or coal when it comes to climate change. But some researchers, most notably Robert Howarth of Cornell University, have argued that they would. Howarth estimates that emissions from natural gas leakage are likely to be in the range of 3.6% to 7.9% of gross national production over the entire natural gas life-cycle (which includes production, processing, transmission, storage, and distribution). He estimates leakage at the wellhead during both well completion and production to

[130] For a brief explanation of life-cycle emissions assessment methodology, see text box "Estimating the GHG Footprint of Unconventional Natural Gas."

[131] Of the 144.7 MMtCO_2e of methane reported, 53.4 MMtCO_2e is from "field production," 19.6 MMtCO_2e is from "processing," 43.8 MMtCO_2e is from "transmission and storage," and 27.9 MMtCO_2e is from "distribution." U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, Washington, DC, EPA 430-R-13-001, April 15, 2013, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Chapter-3-Energy.pdf. For a definition of carbon dioxide equivalent, see footnote 28.

[132] Global-warming potential (GWP) is a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide. A GWP is calculated over a specific time interval, commonly 20, 100 or 500 years. See United Nations Framework Convention on Climate Change, "Global Warming Potentials" webpage, http://unfccc.int/ghg_data/items/3825.php.

[133] As discussed in section "Measurement of Emissions" of this report.

be between 2.2% and 3.8%.[134] At these rates, "the footprint of shale gas is at least 20% greater [than coal] and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years." Others, however, argue that Howarth's analysis is flawed, claiming that he significantly overestimates the fugitive emissions associated with unconventional gas extraction, undervalues the contribution of "green technologies" (e.g., REC) to reducing these emissions, bases the comparison between gas and coal on heat rather than electricity generation (almost the sole use of coal), and assumes a time interval (i.e., 20 years) over which to compute the relative climate impact of gas compared to coal, thus failing to capture the contrast between the long residence time of CO_2 and the short residence time of methane in the atmosphere.[135]

The controversy has led to a number of life-cycle GHG assessments comparing natural gas to coal. Most use the emissions measurement data from the 1996 EPA/GRI study as a starting point for their assumptions. For example: Wigley (2011)[136] considers the effects of methane leakage, changes in radiative forcing due to changes in the emissions of sulfur dioxide and carbonaceous aerosols, and differences in the efficiency of electricity production between coal- and gas-fired power generation, to find, on balance, "these factors more than offset [natural gas's] reduction in warming due to reduced CO_2 emissions" such that "when gas replaces coal there is additional warming out to [the year] 2050 with an assumed leakage rate of 0%, and out to 2140 if the leakage rate is as high as 10%." Hultman (2011),[137] however, estimates that for electricity generation, the GHG impacts of shale gas are 11% higher than those of conventional gas, and only half that of coal for standard assumptions. Fulton (2011)[138] concludes that U.S. gas-fired electricity generation emits 47% less GHG than coal using the IPCC's 100-year global warming potential index for methane, instead of the 20-year index used by Howarth. Jiang (2011)[139] estimates that emissions from coal-fired electric generation are so much greater than gas-combustion plants that a fuel switch would reduce climate-forcing emissions as long as leakage in a natural gas system is less than 14% (using the IPCC 100-year GWP) or 7% (using the IPCC 20-year GWP). Alvarez (2012),[140] however, in an assessment similar to Jiang's, concludes that leakage in the natural gas system would only need to be 3.2% before the overall lifecycle emissions estimates for natural gas electricity generation surpassed those of coal in the near term. Further, powering vehicles with natural gas rather than gasoline would not strike the same balance in the near term unless gas producers bring their leakage rate down to a maximum of 1.6%; and replacing diesel with natural gas would cause greater near-term climate impacts unless

[134] Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations," *Climatic Change*, vol. 106, no. 4 (June 2011), pp. 679-690, http://rd.springer.com/article/10.1007/s10584-011-0061-5.

[135] Lawrence M. Cathles III, Larry Brown, Milton Taam, and Andrew Hunter, "A Commentary on "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea," *Climatic Change*, vol. 113, no. 2 (July 2012), pp. 525-535, http://rd.springer.com/article/10.1007/s10584-011-0333-0.

[136] Tom Wigley, "Coal to Gas: The Influence of Methane Leakage," *Climate Change*, vol. 108, No. 3 (October 2011), pp. 601–608.

[137] Nathan Hultman et al., "The Greenhouse Impact of Unconventional Gas for Electricity Generation," *Environmental Research Letters*, vol. 6, no. 4 (2011). http://iopscience.iop.org/1748-9326/6/4/044008.

[138] Mark Fulton, et al., "Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal," Deutsche Bank Group Climate Change Advisors and Worldwatch Institute, August 25, 2011, http://www.worldwatch.org/system/files/pdf/Natural_Gas_LCA_Update_082511.pdf.

[139] Mohan Jiang, et al., "Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas," Environmental Research Letters, vol. 6 (July-September 2011), http://iopscience.iop.org/1748-9326/6/3/034014/fulltext/.

[140] Ramón A. Alvarez et al., "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure," *Proceedings of the National Academy of Sciences*, vol. 109, no. 17 (April 24, 2012), pp. 6435–6440, http://www.pnas.org/content/109/17/6435.

leak rates were under 1.0%. Alvarez stresses that the climatic effect of replacing other fossil fuels with natural gas may vary widely depending upon the examined time horizon (e.g., 20, 100, or 500 years), the end-use sector (e.g., electricity generation or transportation) and the fuel replaced (e.g., coal, gasoline, or diesel).

Estimating the GHG Footprint of Unconventional Natural Gas

Life-cycle assessment (LCA) is an analytic method used for evaluating and comparing the environmental impacts of various products (in this case, the climate change implications of hydrocarbon resources). LCA can be used in this way to identify, quantify, and track emissions of carbon dioxide and other GHG emissions arising from the development of these hydrocarbon resources, and to express them in a single, universal metric of carbon dioxide equivalent (CO_2e) GHG emissions per unit of fuel or fuel use. This figure is commonly referred to as the "emissions intensity" of a fuel. The results of an LCA can be used to evaluate the GHG emissions intensity of various stages of the fuel's life-cycle, as well as to compare the emissions intensity of one type of fuel or method of production to another.

As researchers point out: "Gas produced from unconventional wells has roughly the same methane content as that produced from conventional wells and therefore combustion can be assumed to yield the same climate effect. However, extraction techniques for unconventional gas differ from those used for conventional gas, and figures on well-lifecycle methane emissions have not been comprehensively established. Calculating the GHG footprint of unconventional gas requires three steps and associated assumptions. First, emissions of GHG from the production process, leaked methane and CO_2, must be estimated. Second, these numbers must be converted to a common GHG metric such as CO_2-equivalent (CO_2e). Third, because electricity generation technologies vary greatly in their combustion efficiencies, the emissions attributable to a kilogram or GJ of fuel are more appropriately compared on the basis of electricity delivered to the end-user—i.e. on a per kWh basis."[141]

Different published studies have approached these three inputs differently, accounting for the wide spectrum of estimates for natural gas's GHG footprint in comparison to coal, oil, or other fuel sources.

Cost Benefit Analysis of Federal Standards

Natural gas is a product of—and thus a source of revenue for—the oil and gas industry. It is also a main source of pollution from the industry when it is emitted into the atmosphere. Due to this unique linkage, pollution abatement has the potential to translate into economic benefits for the industry, as producers may be able to offset compliance costs with the value of natural gas and its byproducts recovered and sold at market. To capitalize on these incentives, many recovery technologies have been incorporated into industry practices, and have thus served as the basis for several local, state, and federal regulations. The 2012 federal air standards require natural gas producers to use recovery technologies to capture approximately 95% of the methane and VOCs that escape into the air as a result of hydraulic fracturing operations. The agency estimates that the equipment and the activities required to comply with the 2012 standards will cost producers about $170 million a year, but calculates that incorporating the sale of recovered products into the cost will result in an estimated net gain of about $11 million to $19 million a year. The industry disagrees with these estimates and counters with compliance cost estimates at more than $2.5 billion annually. Third parties, such as Bloomberg Government, project a net cost between $316 million and $511 million, or, approximately 1% of industry's annual revenue. All estimates are based on assumptions regarding the quantity of captured emissions, the cost and availability of capital equipment, and the market price for natural gas. In light of these considerations, Congress may opt to examine ways in which to best align the costs of requirements with sustainable resource expansion, industry growth, and job creation.

EPA estimates the 2012 air standards would yield a cost savings of $11 million to $19 million in 2015, as pollution abatement costs would be offset by the value of natural gas and condensate

141 Nathan Hultman et al., *op cit.*

recovered and sold at market. EPA's annual cost estimates include (1) cost of capital, (2) operating and maintenance costs, (3) cost of monitoring, inspection, recordkeeping and reporting (MIRR), and (4) associated product recovery credits. All costs are reported in 2008 dollars, and calculated as follows: The total estimated net annual cost to industry to comply with the final amendments in the Crude Oil and Natural Gas Production NESHAPs is approximately $3.3 million. The total estimated net annual cost in the Natural Gas Transmission and Storage NESHAPs is approximately $180,000. The total estimated net annual cost to industry to comply with the final NSPS is approximately $170 million; and, when revenues from additional product recovery are considered, the final NSPS is estimated to result in a net annual engineering cost savings of approximately $15 million. EPA assumes that producers will be paid $4/Mcf for the recovered gas at the wellhead and $70 per barrel for recovered condensate, with about 43 million Mcf (i.e., 43 billion cubic feet) of natural gas and 160,000 barrels of condensate recovered by control requirements in 2015. Further, EPA estimates that the operation cost of 3-10 days of hydraulic fracturing with reduced emissions completions would be $700 to $6,500 per day with an additional $3,500 per well for flare equipment, for an average incremental cost of using the abatement technology of $33,237 per completion. EPA annualizes the cost using a 7% discount rate.

The American Petroleum Institute (API), in its comments to EPA on the proposed regulation, included a consultant's report that projects compliance costs of more than $2.5 billion annually after accounting for incremental sales of the fuel.[142] API estimates the cost of flaring emissions to be $90,000 per well, and the operation cost of using (i.e., renting and setting up) reduced emissions completions to be $180,000 per completion. API reports that only 300 REC sets are currently in existence, with the capacity to produce only 4,000 wells a year. Working with EPA's projection that there would be 25,000 new or modified hydraulically fractured wells completed annually, API argues that the equipment prescribed to conduct reduced emission completions would not be available in time to comply with the rule schedule. Further, API contends that EPA's cost analyses are based on "average model facilities" that do not represent all equipment and compliance costs and fail to identify when the controls are no longer economic. At the time of the proposed rule, API's consultant claimed that the proposed air standards could create "a significant slowdown in unconventional resource development ... resulting in less reserve additions, less production, lower royalties to the Federal government and private landowners, and lower severance tax payments to state governments. The delays in drilling result in delays in production, which result in the delays in the economic benefits associated with that production." Other industry commentators have gone further by stating that the full burden of regulations would fall squarely upon the producers, because economic incentives dictate that producers are currently capturing and selling all economically recoverable natural gas. EPA's rule would "divert investments from capital and energy development into regulatory compliance efforts, and impose onerous notification, record keeping, monitoring, reporting, and performance testing requirements that industry will necessarily incur costs to keep up with."[143]

In the final *Regulatory Impact Assessment* issued in April 2012, EPA examines the compliance costs for slightly more than 11,000 hydraulically fractured wells that would be drilled in unconventional formations, and nearly 1,500 that would be re-fractured to stimulate production.

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[142] Advanced Resources International Inc., *Estimate of Impacts of EPA Proposals to Reduce Air Emissions from Hydraulic Fracturing Operations*, prepared for the American Petroleum Institute, February 2012, http://www.api.org/~/media/Files/Policy/Hydraulic_Fracturing/NSPS-OG-ARI-Impacts-of-EPA-Air-Rules-Final-Report.ashx.

[143] Thomas J. Pyle, "EPA's Flawed Rule Warrants Scrutiny," *National Journal*, April 23, 2012, http://energy.nationaljournal.com/2012/04/regulating-natural-gas-whats-t.php#2201556.

Of those, approximately 6,600 are assumed to be using reduced emissions completions voluntarily or under state/local regulations, and an additional 12% would be classified as exploratory, delineation, or low-pressure wells exempt from the 2012 standards, leaving about 4,600 that would be compelled to use REC as a result of federal regulation.[144] API, however, claims that most large producers in the natural gas sector are currently using REC where feasible and "where it makes economic sense." Chesapeake Energy, the number two U.S. gas producer, has said it limits emissions on "a very high percentage" of its wells. Fourth-ranked Devon Energy has stated it uses REC for 91% of its wells. A survey of nine API members working in 29 drilling areas reported their members doing REC on 70% of their wells. America's Natural Gas Alliance (ANGA) submitted a survey to EPA of eight unidentified production companies that report using REC on 93% of their wells in 2011.[145] As with any self-selected and self-reported survey, it is difficult to determine how representative these samples are of overall industry practice.

A comparative report by Bloomberg Government—using slightly different values to analyze the available data on affected wells, compliance costs, products recovered, and market prices—calculates that the costs would fall somewhere in between both EPA's and API's projections. In their analysis, the regulation would generate an initial $125 million in spending on new equipment and $383 million in annual rental and service fees beginning in 2015. Factoring in product recovery, the total net costs of compliance would fall between $316 million and $511 million per year depending upon the market price of natural gas—or, more than twice the amount estimated by EPA and less than half that projected by API. This increase would account for approximately 0.5% to 0.7% of the industry's 2011 gas sales, which they determined "may cause a slight reduction in drilling activity."[146] Bloomberg Government noted that EPA's analysis assumed natural gas prices 40% above levels at the time and estimates that prices would need to rise to $10/Mcf to make the value of recovered products equal to the compliance costs.

Relevant Legislation in the 113th Congress

Legislation in the 113th Congress to amend the Clean Air Act to address emissions from crude oil and natural gas production activities includes the following:

The BREATHE Act. On March 14, 2013, Representative Jared Polis (D-CO-2) and 40 co-sponsors introduced H.R. 1154, a bill "to amend the Clean Air Act to eliminate the exemption for aggregation of emissions from oil and gas development sources, and for other purposes." Dubbed the Bringing Reductions to Energy's Airborne Toxic Health Effects Act, or BREATHE Act, the

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[144] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry,* April 2012, p. 3-6, http://www.epa.gov/ttnecas1/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf.

[145] Comments to "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," submitted by Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute, November 30, 2011, accessed on http://www.regulations.gov; Jim Efstathiou Jr. and Mark Drajem," Gas Groups' Strategies Diverge in Opposing Obama Fracking Rules," *Bloomberg News*, March 26, 2012, http://www.bgov.com/news_item/tChIVzjpbV4O4xTaVVX-FA; Comments submitted by Devon Energy, Nov. 30, 2011, accessed on http://www.regulations.gov; David A. Simpson, P.E., *Review of the Regulatory Impact Analysis (RIA) for the Well Completions Portion of the Proposed New Source Performance Standards for the Oil and Natural Gas Industry,* Attachment G to comments by API, op cit.; Comments submitted by Amy Farrell, Vice President of Regulatory Affairs, America's Natural Gas Alliance (ANGA) and Bruce Thompson, President, American Exploration and Petroleum Council (AXPC), November 30, 2011, accessed on http://www.regulations.gov.

[146] Rich Heidorn Jr., *Fracking Emission Rules: EPA, Industry Miss Mark on Costs, Consequences,* Bloomberg Government, 2012, http://about.bgov.com/2012/07/19/fracking-emissions-rules-re-estimating-the-costs/. The report cites EIA figures of 24 trillion cubic feet of gas sold by U.S. natural gas producers in 2011, with a value of $72.5 billion at $3/Mcf.

proposed bill would amend the CAA to (1) include hydrogen sulfide in the list of hazardous air pollutants, and (2) repeal the exemption on aggregating emissions from any oil or gas sources for any purpose relating to hazardous air pollutant emission standards. The bill was referred to the House Committee on Energy and Commerce on March 14, 2013.

Conclusion

U.S. natural gas production has grown markedly in recent years. This growth is due in large part to increased activities in unconventional resources brought on by technological advance. Many have advocated for the increased production and use of natural gas in the United States for economic, national security, and environmental reasons. They argue that natural gas is the cleanest-burning fossil fuel, with fewer emissions of carbon dioxide, nitrogen oxide, sulfur dioxide, particulate matter, and mercury than its hydrocarbon rivals (e.g., coal and oil) on a per-unit-of-energy basis. For these reasons, many have looked to natural gas as a "bridge" fuel to a less polluting and lower greenhouse gas-intensive economy. However, the recent expansion in natural gas production in the United States has given rise to a new set of concerns regarding human health and environmental impacts, including impacts on air quality.

To address air quality and other environmental issues, the oil and gas industry in the United States has been regulated under a complex set of local, state, and federal laws. Currently, state and local authorities are responsible for virtually all of the day-to-day regulation and oversight of natural gas systems, and many states have passed laws and/or have promulgated rules to address air quality issues based on local needs. Further to this, organizations like the State Review of Oil and Natural Gas Environment Regulations (STRONGER) are available to help states assess the overall framework of environmental regulations supporting oil and gas operations in their regions.[147] At the federal level, EPA has promulgated minimum national standards for VOCs, SO_2, and HAPs for some source categories in the crude oil and natural gas sector. The federal air standards focus primarily on the production and processing sectors of the industry, and were drawn, in part, from existing requirements found in the state codes of Colorado and Wyoming. Further to this, many producers in the crude oil and natural gas sector have set forth a series of recommended practices. These practices are sustained by the economic incentives provided by capturing the fugitive releases of natural gas and its byproducts to be sold at market. Several voluntary partnerships sponsored by various federal and international agencies also serve to facilitate recommended practices for emissions reductions in the oil and gas industry. EPA's Natural Gas STAR Program, the Global Methane Initiative (formerly the Methane to Markets Partnership), and the World Bank Global Gas Flaring Reduction Partnership are three such programs.[148]

Many believe that air standards similar to those promulgated by Colorado, Wyoming, and the federal government are sufficient to control VOC, SO_2, and HAP emissions from the natural gas production sector. Some argue that the cost of compliance with state and federal air standards could affect industry profits, thereby reducing economic interest to invest and slowing production

[147] STRONGER is a non-profit, multi-stakeholder organization which specializes in assessing the overall framework of environmental regulations supporting oil and gas operations. Their collaborative review teams encompass industry, regulators, and environmental/public interest stakeholders. Since its initiation, STRONGER has completed reviews of 21 state programs responsible for the regulation of over 90% of the domestic onshore production of oil and natural gas. Stronger has completed specific hydraulic fracturing reviews in Colorado, Louisiana, Oklahoma, Pennsylvania, and Ohio. For more information, see http://www.strongerinc.org/.

[148] For more information about EPA's Natural Gas STAR Program, see http://www.epa.gov/gasstar/. For the Global Methane Initiative, see EPA's website, http://www.epa.gov/globalmethane/index.htm. For the Global Gas Flaring Reduction Partnership, see the World Bank's website, http://go.worldbank.org/KCXIVXS550.

activities. Others are concerned that some pollutants and some emission sources remain unregulated by any standard, including methane, hydrogen sulfide, oil wells, offshore wells, conventional gas wells, and most operations downstream of the gas processing plant. Debate over the costs of compliance, covered sources and pollutants, and the proper regulatory institutions (i.e., local, state, or federal) continues. Complicating these debates is the fact that a comprehensive national inventory that directly measures the quantity and composition of fugitive emissions from natural gas systems does not exist. This is due to many factors, including costs and technical uncertainties. But, until there is an adequate and reliable assessment of industry-wide emissions, the benefits, costs, and basis for regulation may remain uncertain.

Appendix A. Federal Air Standards for Crude Oil and Natural Gas Systems

Table A-1. New Source Performance Standards for Volatile Organic Compounds in Crude Oil and Natural Gas Systems

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
Natural Gas Well Sites	**New Hydraulically Fractured Well Completions**	Not covered.	Exploratory wells: operators must use completion combustion device (e.g., flaring) unless hazardous or prohibited by state or local regulations.	October 15, 2012.	Exploratory well defined as a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.
			Delineation wells: operators must use completion combustion device (e.g., flaring) unless hazardous or prohibited by state or local regulations.	October 15, 2012.	Delineation well defined as a well drilled in order to determine the boundary of a field or producing reservoir.
			Hydraulically fractured low-pressure wells: operators must use completion combustion device (e.g., flaring) unless hazardous or prohibited by state or local regulations.	October 15, 2012.	Low pressure well defined by a formula based on well depth and pressure. (A well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.) EPA estimates that this exclusion for low pressure gas wells would cover 10% of all natural gas wells and, specifically, 87% of coal-bed methane wells.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
			All other hydraulically fractured wells, prior to January 1, 2015: operators must use either completion combustion device (e.g., flaring) or reduced emissions completion (i.e., "green completion").	Prior to January 1, 2015.	Completion combustion device defined as any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.
			All other hydraulically fractured wells, after January 1, 2015: operators must use reduced emissions completion (i.e., "green completion").	On or after January 1, 2015.	Reduced emissions completion defined as a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere. The extended compliance date is to allow for the availability of REC equipment. Of note, the rule provides that if using REC technology is "infeasible" or "unsafe," the operator may use a completion combustion device to control flowback emissions.
			Notification and annual reporting requirements.	October 15, 2012.	Owners or operators of hydraulically fractured and refractured natural gas wells must notify EPA (or in some cases, a state or local air agency) by e-mail no later than two days before completion work begins. Further, each year, owners/ operators must submit a report on all well completion activities during the year.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
	Refractured Natural Gas Well Completions	Not covered.	All wells that are refractured or recompleted prior to January 1, 2015: the well will not be considered "modified" under the Clean Air Act if operators use reduced emissions completions (i.e., "green completion") rather than flaring.	Prior to January 1, 2015.	The provisions are designed to encourage operators to use REC technology before it is required, and will allow operators in many states to refracture wells without triggering additional state permitting requirements. EPA believes that this provision will result in an additional 1,000 to 1,500 REC.
			All wells that are refractured or recompleted on or after January 1, 2015: operators must use reduced emissions completion (i.e., "green completion").	On or after January 1, 2015.	The provisions are equivalent to new fractured wells.
	New & Modified Compressors	Not covered.	Not covered.	N/a.	N/a.
	New & Modified Pneumatic Controllers	Not covered.	Natural gas-driven, continuous-bleed devices with bleed rate greater than 6 standard cubic feet per hour (scfh): operators must reduce natural gas bleed rate to less than 6 scfh.	1-year phase-in period beginning October 15, 2012.	The provisions are designed to exclude pneumatic controllers that meet the NSPS standard (e.g., low-bleed, intermittent-bleed, and/or non-gas-driven devices), exempting them from the recordkeeping and reporting requirements of the rule to encourage operators to install.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
	New Storage Vessels	Not covered.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	Storage vessel defined as a tank or other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of liquids or other materials. It excludes skid-mounted vessels and mobile vessels attached to vehicles that are intended to remain at a site for less than 180 consecutive days, as well as process vessels, and pressure vessels designed to operate in excess of 204.9 kilopascals with no emissions to the atmosphere. The extended compliance date is to allow for the availability of control devices.
Natural Gas Gathering & Boosting Stations	**New & Modified Compressors**	Not covered.	Centrifugal compressors with wet-seals: operators must utilize a control system that captures emissions from the wet seal fluid degassing system and routes them to a control device in order to reduce VOCs emissions by at least 95%.	October 15, 2012.	Centrifugal compressors with dry-seals are exempt from the 2012 rules due to low VOCs emissions.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
			Reciprocating compressors: operators required to change rod packings after either 26,000 hours (operating hours must be monitored and documented) or 36 months of operation.	October 15, 2012.	Operating hours must be monitored and documented for usage by hour, but monitoring is waived if operators choose the 36 month requirement.
	New & Modified Pneumatic Controllers	Not covered.	Natural gas-driven, continuous-bleed devices with bleed rate greater than 6 standard cubic feet per hour (scfh): operators must reduce natural gas bleed rate to less than 6 scfh.	1-year phase-in period beginning October 15, 2012.	The provisions are designed to exclude pneumatic controllers that meet the NSPS standard (e.g., low-bleed, intermittent-bleed, and/or non-gas-driven devices), exempting them from the recordkeeping and reporting requirements of the rule to encourage operators to install.
	New Storage Vessels	Not covered.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	(See definition of "Storage Vessel" above.)

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
Natural Gas Processing Plants	**New & Modified Compressors**	Covered under LDAR program	Centrifugal compressors with wet-seals: operators must utilize a control system that captures emissions from the wet seal fluid degassing system and routes them to a control device in order to reduce VOCs emissions by at least 95%.	October 15, 2012.	Centrifugal compressors with dry-seals are exempt from the 2012 rules due to low VOCs emissions.
			Reciprocating compressors: operators required to change rod packings after either 26,000 hours or 36 months of operation.	October 15, 2012.	Operating hours must be monitored and documented for usage by hour, but monitoring is waived if operators choose the 36 month requirement.
	New & Modified Pneumatic Controllers	Covered under LDAR program.	Natural gas-driven, continuous-bleed devices: operators must reduce natural gas bleed rate to zero scfh.	October 15, 2012.	The standards for pneumatic controllers at natural gas processing plants reflect the emission level achievable from the use of non-natural gas-driven pneumatic controllers.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
	New Storage Vessels	Covered under LDAR program.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	(See definition of "Storage Vessel" above.)
	Leak Detection and Repair	The prior NSPS for equipment leaks of VOCs at natural gas processing plants (40 C.F.R. Part 60, subpart KKK) requires compliance with specific provisions of 40 C.F.R. Part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks.	Existing NSPS requirements for LDAR revised to reflect the procedures and leak thresholds established by 40 C.F.R. 60, subpart VVa: Subpart VVa lowers the leak definition for valves from 10,000 ppm to 500 ppm, and requires the monitoring of connectors, pumps, pressure relief devices, and open-ended valves or lines.	October 15, 2012.	EPA excludes compressors from the leak detection and repair (LDAR) requirements applicable to equipment at onshore natural gas processing plants because the rule already imposes control requirements on compressors.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
Natural Gas Transmission, Storage, and Distribution	**New & Modified Compressors**	Not covered.	Not covered.	N/a.	EPA states that it needs additional information in order to set cost-effective standards in this sector where VOCs content of gas is generally low.
	New & Modified Pneumatic Controllers	Not covered.	Not covered.	N/a.	EPA states that it needs additional information in order to set cost-effective standards in this sector where VOCs content of gas is generally low.
	New Storage Vessels	Not covered.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	(See definition of "Storage Vessel" above.)
Oil Well Sites	**Well Completions**	Not covered.	Not covered.	N/a.	EPA excludes oil wells from requirements. Only "gas wells" or "natural gas wells" defined as onshore wells drilled principally for the production of natural gas are covered.
	New & Modified Compressors	Not covered.	Not covered.	N/a.	N/a.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
	New & Modified Pneumatic Controllers	Not covered.	Natural gas-driven, continuous-bleed devices with bleed rate greater than 6 standard cubic feet per hour (scfh): operators must reduce natural gas bleed rate to less than 6 scfh.	1-year phase-in period beginning October 15, 2012.	The provisions are designed to exclude pneumatic controllers that meet the NSPS standard (e.g., low-bleed, intermittent-bleed, and/or non-gas-driven devices), exempting them from the recordkeeping and reporting requirements of the rule to encourage operators to install.
	New Storage Vessels	Not covered.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	(See definition of "Storage Vessel" above.)

Source: U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012; U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013; and 40 C.F.R. Part 60, Subpart KKK.

Table A-2. New Source Performance Standards for Sulfur Dioxide in Crude Oil and Natural Gas Systems

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart LLL	**40 C.F.R. Part 60, Subpart OOOO**	**77 FR 49489, August 16, 2012**	**New or Modified Facilities Defined as Beginning Construction After August 23, 2011**
Natural Gas Processing Plants	**New and Modified Sweetening Units**	Sweetening units at onshore affected natural gas processing plants: operator required to achieve an SO_2 emission reduction efficiency determined from an equation based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility.	Sweetening units at onshore affected natural gas processing plants: operators must reduce SO_2 emissions for units with sulfur production rate of at least 5 long tons per day based on sulfur feed rate and sulfur content of gas.	October 15, 2012.	Sweetening unit defined as a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Source: U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012; and 40 C.F.R. Part 60, Subpart LLL.

Table A-3. National Emissions Standards for Hazardous Air Pollutants in Crude Oil and Natural Gas Systems

Source Sector	Affected Facility	Prior Rules 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	2012 Rules 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	Compliance Dates 77 FR 49489, August 16, 2012	Comments New or Modified Facilities Defined as Beginning Construction After August 23, 2011
Major Sources, All Sectors	**Large Dehydrators**	Glycol dehydration units at major sources that have annual average natural gas throughputs of 85,000 cubic meters a day or emit an average of one ton or more of benzene annually: required to connect, through a closed vent system, each process vent to an air emission control system. The control system must reduce emissions: (1) by 95% or more of HAPs, (2) to an outlet concentration of 20 parts per million by volume (ppmv) or less (for combustion devices), or (3) to a benzene emission level of one ton per year or less.	Retains existing standards.	N/a.	The final rule eliminated the exemption for periods of startup, shutdown, and malfunction.
	Small Dehydrators	Not covered.	Small glycol dehydrators that have annual average natural gas throughputs of less than 85,000 standard cubic feet per day or emit an average of less than one ton of benzene annually: required to comply with unit-specific limits on annual emissions of benzene, toluene,	October 15, 2012, for new units; October 15, 2015, for existing units.	The final rule eliminated the exemption for periods of startup, shutdown, and malfunction.

Source Sector	Affected Facility	Prior Rules 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	2012 Rules 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	Compliance Dates 77 FR 49489, August 16, 2012	Comments New or Modified Facilities Defined as Beginning Construction After August 23, 2011
			ethylene, and xylene (collectively, "BTEX").		
	Storage Vessels	Storage vessels at major sources with the potential for flash emissions: required to have either a closed vent system that is linked to a control device that either recovers or destroys 95% or more of HAPs emissions, or a combustion device (such as flares) that reduces HAPs emissions to an outlet concentration of 20 ppmv or less.	Retains existing standards	N/a.	The final rule eliminated the exemption for periods of startup, shutdown, and malfunction. EPA chose not to promulgate new standards covering non-flash potential storage tanks (e.g., crude oil and condensate storage tanks) because it determined that additional data is necessary to establish the MACT standard.
	Leak Detection and Repair	Natural gas processing plants that are major HAPs sources: control HAPs emissions from leaks from ancillary equipment and compressors. The owner or operator of such equipment is required to implement a Leak Detection and Repair (LDAR) program and where necessary, perform equipment modifications.	Under the 2012 standards, a leak triggering the rule's LDAR requirements is strengthened to include any measurement exceeding 500 ppm of any regulated HAPs.	October 15, 2012.	The final rule eliminated the exemption for periods of startup, shutdown, and malfunction.
	Associated Equipment	Associated equipment for major source determinations defined as equipment associated with an oil or natural gas exploration or	Associated equipment for major source determinations amended to exclude emissions from all storage vessels.	October 15, 2012.	The treatment of HAPs emissions from oil and gas production has differed from the general requirements of Section 112 of the CAA. Section 112(n)(4) provides that,

Source Sector	Affected Facility	Prior Rules 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	2012 Rules 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	Compliance Dates 77 FR 49489, August 16, 2012	Comments New or Modified Facilities Defined as Beginning Construction After August 23, 2011
		production well, including all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels with the potential for flash emissions.			notwithstanding the general definition of "major source," … "emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources." Thus, for facilities that are production field facilities, only HAPs emissions from glycol dehydration units and storage vessels are aggregated for a major source determination. For facilities that are not production field facilities, HAPs emissions from all HAPs emission units are aggregated for a major source determination.

Source: U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012; U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013; and 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector).

Notes: The NESHAPs in the table cover "Major Sources" of air toxics in the Crude Oil and Natural Gas Production Sector, and in the Natural Gas Transmission and Storage Sector. "Major Source" is defined as emitting 10 or more tons of a single air toxic and 25 tons or more of a combination of toxics in a year.

Table A-4. Comparison of 2012 Federal Air Standards for Crude Oil and Natural Gas Systems to Selected State Regulations

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Well Completions	Hydraulically fractured wildcat, delineation, and low-pressure natural gas wells must route flowback emissions to completion combustion device. All other hydraulically fractured natural gas wells must route flowback emissions to completion combustion device or use green completions prior to January 1, 2015, and must use green completions after January 1, 2015, unless "infeasible."	COGCC HB-07-1341, Section 805.b(3). Green completions shall be used when technically and economically feasible. If not feasible, Best Management Practices shall be used.	MT DNRC BOGC 36.22.1221. All gas vented to the atmosphere at a rate exceeding 20 MCF per day for a period in excess of 72 hours shall be burned.	None.	None.	None.	C6 S2 O&G Permitting Guidance. Green completions are required in the JPAD area and CDA in Wyoming as of August 1, 2011.
Processing Plants	Equipment leaks at onshore natural gas processing plants require a LDAR program.	Colorado has adopted NSPS Subpart KKK on LDAR under Reg. 7, XII.G.1 (KKK applies at gas processing plants located in ozone non-attainment areas regardless of the date of construction of the affected facility).	Montana has adopted NSPS Subpart KKK on LDAR.	New Mexico has adopted NSPS Subpart KKK on LDAR.	North Dakota has adopted NSPS Subpart KKK on LDAR.	Utah has adopted NSPS Subpart KKK on LDAR.	Wyoming has adopted NSPS Subpart KKK on LDAR.

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Pneumatic Controllers	Continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants must meet natural gas bleedrate of zero. Continuous bleed natural gas-driven pneumatic controllers with a bleed rate greater than 6 scfh between wellhead and natural gas processing plant must meet natural gas bleedrate less than 6 scfh.	Reg. 7, XVIII.C.1. No or low-bleed pneumatic devices required for all new & existing applications. (exceptions allowed) (only applies in ozone non-attainment areas). COGCC HB-07-1341, Section 805.b(2)E. No or low-bleed required for new, repaired or replaced devices where technically feasible.	17.8.1603(1)(a). VOCs vapors (> 500 BTU/scf) from O&G wellhead equipment must be captured and routed to a gas pipeline if within ½ mile, or to emissions minimizing technology or smokeless combustion device. 17.8.1711(1)(a). VOCs vapors (>200 Btu/scf) from each piece of O&G well facility equipment, with a PTE > 15 tpy, must be captured and routed to a gas pipeline, or routed to air pollution control equipment with a 95% or greater control efficiency. 17.8.752. Requires a case by case BACT determination.	None.	None.	None.	C6 S2 O&G Permitting Guidance. Install low or no-bleed at all new facilities. Upon modification of facilities, new pneumatic controllers must be low/no-bleed and existing controllers must be replaced with no/low-bleed. (Well site facilities only—not gas plants.)

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Compressors	Centrifugal compressors with dry seals are exempt. Centrifugal compressors with wet seals must reduce emissions by 95%. Reciprocating compressors must change rod packing after 26,000 hours or after 36 months.	None.	17.8.1603(1)(a). VOCs vapors (> 500 BTU/scf) from O&G wellhead equipment must be captured and routed to a gas pipeline if within ½ mile, or to emissions minimizing technology or smokeless combustion device. 17.8.1711(1)(a). VOCs vapors (>200 Btu/scf) from each piece of O&G well facility equipment, with a PTE > 15 tpy, must be captured and routed to a gas pipeline, or routed to air pollution control equipment with a 95% or greater control efficiency. 17.8.752. Requires a case by case BACT determination.	None.	None.	None.	None.

Storage Vessels	Storage vessels with VOCs emissions equal to or greater than 6 tpy must reduce emissions by 95%. Proposal under 78 FR 22125 to revise storage vessel standards to include a sustained uncontrolled VOC emission rate of less than 4 tpy as an alternative emission limit to the 95% control under specified circumstances. HAPs at production facilities must reduce emissions by 95%.	Reg. 7, XII.G.2. 95% VOCs reduction at gas processing plants if uncontrolled emissions from condensate tanks are ≥ 2 tpy (only applies in ozone non-attainment areas). Reg. 7, XVII.C.1. 95% VOCs reduction for condensate storage tanks if uncontrolled emissions ≥ 20 tpy. Reg. 7, XIID. Condensate tanks in ozone non-attainment areas shall be controlled under a system wide approach. COGCC HB-07-1341, Section 805.b(2)A). 95% VOCs reduction for liquids condensate & crude oil tanks if uncontrolled emissions ≥ 5 tpy within 1/4 mile of an affected building (Garfield, Mesa & Rio Blanco).	17.8.1603(1)(b). VOCs vapors from O&G oil or condensate storage tanks with a PTE > 15 tpy must be routed to a gas pipeline or emissions minimizing technology. Registration - 17.8.1711 (1)(a). VOCs vapors from each piece of O&G well facility equipment with PTE >15 tpy must be captured and routed to a gas pipeline, or routed to air pollution control equipment with a 95% or greater control efficiency. 17.8.1711(1)(b). Requires submerged filling technology on all hydrocarbon liquid loading or unloading.	None.	NDAC Section 33-15-07. Submerged filling requirements for tanks >1,000 gallons and control of organic compounds.	R307-327 Ozone Nonattainment Area. Volatile Petroleum Liquid Tanks (> 40,000 gallons, true vapor pressure (TVP) > 1.52 psia at storage temperature) shall be controlled to minimize vapor loss. New tanks shall be fitted with an internal floating roof resting on the liquid surface with the space (roof edge to tank wall) sealed. Owner/operator shall maintain records of the liquid type/ maximum TVP. Records required of average monthly storage temperature, the liquid type, throughput and maximum TVP for tanks not subject to above (petroleum liquid TVP > 1.0 psia).	C6 S2 O&G Permitting Guidance. JPAD - 98% control of all new/modified tank emissions upon startup/modification. CDA - 98% control of all new/modified tank emissions ≥ 8 tpy VOCs within 60 days of startup/ modification. Statewide - 98% control of all new/ modified tank emissions ≥10 tpy VOCs within 60 days of startup/ modification.

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Dehydrators	95% reduction of HAPs in all large glycol dehydrators (> 3 MMCFD or > 1 tpy benzene emissions). Small dehydrator emission limits of 4.66 E-6 grams BTEX/scm-ppmv (new units) or 1.1 E-4 grams BTEX/scm-ppmv (existing units)	Reg. 7, XII.H and XVII.D. 90% reduction of VOCs where uncontrolled VOCs emissions ≥ 15 tpy. COGCC HB-07-1341, Section 805.b(2)C). 90% reduction of VOCs required where uncontrolled VOCs emissions ≥ 5 tpy within 1/4 mile of an affected building (applies only to Garfield, Mesa & Rio Blanco Counties).	17.8.1603(1)(a). VOCs vapors (> 500 BTU/scf) from O&G wellhead equipment must be captured and routed to a gas pipeline if within ½ mile, or to emissions minimizing technology or smokeless combustion device. 17.8.1711(1)(a). VOCs vapors (>200 Btu/scf) from each piece of O&G well facility equipment, with a PTE > 15 tpy, must be captured and routed to a gas pipeline, or routed to air pollution control equipment with a 95% or greater control efficiency. 17.8.752. Requires a case by case BACT determination.	None.	TEG units with a condenser require temperature monitoring.	None.	C6 S2 O&G Permitting Guidance. JPAD - 98% control of all new/modified dehydrator VOCs/HAPs emissions at start up. CDA & Statewide - PAD Facilities - 98% control upon startup. SINGLE Well Facilities - 98% control within 60 days of startup for VOCs emissions ≥6 OR 98% control within 30 days of startup for VOCs emissions ≥8 tpy.

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Minor Source Permitting	exempt	Reg. 3 Part B, II.D. Minor Source permitting required for sources with thresholds that vary by pollutant and area (generally required in non-attainment areas for criteria emissions > 1-5 tpy – required statewide for criteria emissions > 5-10 tpy – thresholds depend on the pollutant).	17.8.743 Montana Air Quality Permits (MAQP). NSR permitting required for sources with > 25 tpy PTE. 17.8.1702. A registration eligible facility may register in lieu of obtaining a MAQP.	20.2.72 NMAC. Requires permits for all sources >25 tpy of a criteria pollutant. 20.2.73 NMAC. Requires Notices of Intent for all sources >10 tpy of a criteria pollutant	None. (Registration of O&G facilities required per Chapter 33-15-20 rules in lieu of a permit.)	UAC Rule 307-401-9. NSR permitting exempted for sources with controlled emissions below de minimis levels: PTE< 5 tpy each PM10, NOx, SOx, CO, VOCs, or single HAPs < 500 lbs per year, combined HAPs < 1 tpy.	Emissions from minor sources must be approved through permitting applied through the WAQSR Chapter 6 Section 2(a)(i) O&G Permitting Guidance. For VOCs emissions ≥8 tpy from sources other than tanks, dehydrators, pneumatic controllers and pumps, water tanks, BACT is considered on case-by-case basis.

Source: Federal summaries from U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012, and U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013. State summaries from Lee Gribovicz, *Analysis of States' and EPA Oil & Gas Air Emissions Control Requirements for Selected Basins in the Western United States*, Western Regional Air Partnership, January 8, 2012, http://www.wrapair2.org/pdf/2012-01_Final%20WRAP%20OG%20Analysis%20%2801-08%29.pdf.

a. Wyoming has three area categories: (1) Jonah-Pinedale Anticline Development (JPAD), (2) Concentrated Development Area (CDA) and (3) statewide.

Appendix B. Composition of Fugitive and Combusted Natural Gas Emissions

Fugitive Natural Gas

Fugitive natural gas is primarily a mixture of low molecular-weight hydrocarbon compounds that are gases at surface pressure and temperature conditions. While the principal component of natural gas is methane (CH_4), it may contain smaller amounts of other hydrocarbons, such as ethane, propane, and butane, as well as trace amounts of heavier hydrocarbons. Non-hydrocarbon gases, such as carbon dioxide (CO_2), helium (He), hydrogen sulfide (H_2S), nitrogen (N_2), and water vapor (H_2O), may also be present in any proportion to the total hydrocarbon content (see **Table B-1**).

Table B-1. Composition of Raw Natural Gas

Component	Abbreviation	Percent of Composition
Methane (Natural Gas)	CH_4	70-90
Ethane (Natural Gas Liquid)	C_2H_6	0-20
Propane (Natural Gas Liquid)	C_3H_8	0-20
Butane (Natural Gas Liquid)	C_4H_{10}	0-20
Heavier Hydrocarbons	C_xH_y	0-20
Carbon Dioxide	CO_2	0-8
Oxygen	O_2	0-0.2
Nitrogen	N_2	0-5
Hydrogen Sulfide	H_2S	0-5
Rare Gases	A, He, Ne, Xe	Trace

Source: The Natural Gas Supply Association, http://www.naturalgas.org/overview/background.asp.

Combusted Natural Gas

Combusted natural gas releases carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxides (NOx), and trace amounts of sulfur dioxide (SO_2), particulate matter (PM), uncombusted methane (CH_4), VOCs, and HAPs. Combusted natural gas is generally regarded as "cleaner" than other fossil fuels with respect to various criteria pollutants and greenhouse gas (GHG) emissions (see EPA's and EIA's data comparisons in **Table B-2**). Coal, fuel oil, and petroleum-based transportation fuels are composed of more complex long-chain hydrocarbon molecules, with higher carbon ratios, and may contain higher nitrogen and sulfur contents as well as increased amounts of ash and particulate matter. By comparison, the combustion of natural gas releases minimal amounts of sulfur dioxide and nitrogen oxides, virtually no ash or particulate matter, and lower levels of carbon dioxide, carbon monoxide, and other reactive hydrocarbons. While comparisons among the emission profiles of natural gas, coal, fuel oil, and transportation fuels are useful in certain contexts, it should be noted that these comparisons are not wholly substitutable, as end-uses of the fuels vary across sectors and pollution control mechanisms are in place for many of the fuels' combustion activities.

Table B-2. Air Pollution Emissions by Combusted Fuel Type

Pounds per Billion Btu of Energy Input

Pollutant	Natural Gas	Fuel Oil	Coal
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur Dioxide	1	1,122	2,591
Particulates	7	84	2,744
Formaldehyde	0.750	0.220	0.221
Mercury	0.000	0.007	0.016

Source: Energy Information Administration (EIA), Office of Oil and Gas. Carbon Monoxide: derived from EIA, *Emissions of Greenhouse Gases in the United States 1997,* Table B1, p. 106. Other Pollutants: derived from Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Vol. 1, 1998.*

Notes: No pre- or post-combustion removal of pollutants. Bituminous coal burned in a spreader stoker is compared with No. 6 fuel oil burned in an oil-fired utility boiler and natural gas burned in an uncontrolled residential gas burner. Conversion factors are: bituminous coal at 12,027 Btu per pound and 1.64% sulfur content; and No. 6 fuel oil at 6.287 million Btu per barrel and 1.03% sulfur content—derived from Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants* (1996).

Appendix C. Glossary of Terms

Table C-1. Glossary of Terms Related to Crude Oil and Natural Gas Systems

As defined by the U.S. Environmental Protection Agency in the Final Rules

Terminology	Definition
Bleed rate	The rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.
Centrifugal compressor	Any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.
City gate	The delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.
Completion combustion device	Any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.
Compressor station	Any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.
Continuous bleed	A continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.
Dehydrator	A device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).
Delineation well	A well drilled in order to determine the boundary of a field or producing reservoir.
Exploratory well	A well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.
Flare	A thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.
Flowback	The process of allowing fluids to flow from a natural gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The flowback period begins when material introduced into the well during the treatment returns to the surface immediately following hydraulic fracturing or refracturing. The flowback period ends with either well shut in or when the well is producing continuously to the flow line or to a storage vessel for collection, whichever occurs first.
Flow line	A pipeline used to transport oil and/or gas from the well to a processing facility, a mainline pipeline, reinjection, or other useful purpose.
Hydraulic fracturing	The process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.
Hydraulic refracturing	Conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

Terminology	Definition
Intermittent/snap-action pneumatic controller	A pneumatic controller that vents non-continuously.
Low pressure gas well	A well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.
Natural gas-driven pneumatic controller	A pneumatic controller powered by pressurized natural gas.
Natural gas liquids	The hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.
Natural gas processing plant	Any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.
Natural gas transmission	The pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).
Natural gas well	An onshore well drilled principally for production of natural gas.
Non natural gas-driven pneumatic controller	An instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.
Onshore	All facilities except those that are located in the territorial seas or on the outer continental shelf.
Pneumatic controller	An automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.
Pressure vessel	A storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.
Process unit	Components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.
Reciprocating compressor	A piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.
Reciprocating compressor rod packing	A series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.
Reduced emissions completion	A well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.
Salable quality gas	Natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas, regardless of whether such gas is sold.

Terminology	Definition
Storage vessel	A unit that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of liquids or other materials. The following are not considered storage vessels: (1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. (2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels. (3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.
Sweetening unit	A process device that removes hydrogen sulfide and/or carbon dioxide from a "sour" natural gas stream.
Underground storage vessel	A storage vessel stored below ground.
Well	An oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.
Well completion	The process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.
Well completion operation	Any well completion with hydraulic fracturing or refracturing occurring at a gas well affected facility.
Well site	One or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.
Wellhead	The piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Source: U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012.

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